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Draft Environmental Impact Statement Sulfur Oxides Emissions from Fluid Catalytic Cracking Unit Regenerators: Background Information for Proposed Standards

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Research Triangle Park, NC

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Sulfur Oxides Emissions from Fluid Catalytic Cracking Unit Regenerators -

Background Information for Proposed Standards

Emission Standards and Engineering Division

U.S ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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16. ABSTRACT

Standards of performance to control emissions of sulfur oxides (SO_x) from new, modified, and reconstructed fluid catalytic cracking unit regenerators are being proposed under Section 111 of the Clean Air Act. This document contains information on the background and authority, regulatory alternatives considered, and environmental and economic impacts of the regulatory alternatives.

17. KEY WORDS AND DOCUMENT ANALYSIS

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Background Information and Draft Environmental Impact Statement for Fluid Catalytic Cracking Unit Regenerators

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1. The proposed standards of performance would limit emissions of sulfur oxides from new, modified, and reconstructed fluid catalytic cracking unit regenerators. Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution that ". . . causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." EPA Regions V, VI, and IX are particularly affected, since most fluid catalytic cracking unit regenerators are located at petroleum refineries in these regions.

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Quality; members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; Office and Management and Budget; and other interested parties.

3. The comment period for review of this document is 75 days. Mr. Gilbert H. Wood, Standards Development Branch, telephone (919) 541-5578, may be contacted regarding the date of the comment period.

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ABBREVIATIONS

BACT	Best Available Control Technology
CFR	Code of Federal Regulations
CRC	Coke on Regenerated Catalyst
ESP	Electrostatic Precipitator
FCC	Fluidized Catalytic Cracking
FGD	Flue Gas Desulfurization
HTR	High Temperature Regeneration
L/G Ratio	Liquid to Gas Ratio
Mg	Megagram
Mm^3	Million cubic meters
NAAQS	National Ambient Air Quality Standards
sd	Stream day
cd	Calendar day
HDS	Hydrodesulfurization
Sm^3	Standard cubic meters
Nm^3	Normal (standard, dry) cubic meters

METRIC CONVERSION TABLE

Meter (m)	x 3.28	= feet (ft)
Cubic meter (m^3)	x 6.29	= barrel (oil)(bbl)
Cubic meter (m^3)	x 35.31	= cubic feet (ft^3)
Kilogram (kg)	x 2.20	= pound (lb)
Megagram (Mg)	x 1.10	= ton
Pascal (Pa)	x 14.5×10^{-5}	= pounds per square inch absolute (psia)
Degrees Celsius (C°)	C x 1.8 + 32	= degrees fahrenheit (°F)

PREFIXES

Prefix	Symbol	Multiplication Factor
kilo	k	10^3
Mega	M	10^6

1.0 SUMMARY

1.1 REGULATORY ALTERNATIVES

Standards of performance for sulfur oxides emissions from new and modified or reconstructed fluid catalytic cracking (FCC) units in the petroleum refining industry are being developed under the authority of Section 111 of the Clean Air Act.

Four regulatory alternatives are considered. Regulatory Alternative I, the baseline level, represents the level of sulfur oxides emission control currently achieved by FCC units to meet most State and local sulfur oxides regulations. Alternative II would limit sulfur oxides emissions from FCC units to 13.0 kg/1,000 kg coke burn-off. Alternative III would limit sulfur oxides emissions to 9.8 kg/1,000 kg coke burn-off, and Alternative IV would limit these emissions to 6.5 kg/1,000 kg coke burn-off. It is anticipated that either flue gas desulfurization or sulfur oxides reduction catalysts will be used by refiners to meet these regulatory alternatives.

1.2 ENVIRONMENTAL IMPACTS

1.2.1 Air Emissions Impact

Total sulfur oxides emissions from new, modified, and reconstructed FCC units in the fifth year under Regulatory Alternative I (baseline) are 78,800 Mg, compared to 20,100, 15,100, and 10,100 Mg under Alternatives II, III, and IV, respectively. The average percent emissions reduction from the baseline level are 74, 81, and 87 percent for Regulatory Alternatives II, III, and IV, respectively.

1.2.2 Water and Solid Waste Impacts

The application of sodium-based scrubbers for control of sulfur oxides results in a wastewater discharge which must be treated and disposed. Implementation of Regulatory Alternatives II, III, or IV would increase wastewater discharges in the fifth year by 2.4 Mm^3. The treated wastestream would contain about 98 Mg/yr of suspended solids, 12 kg of dissolved solids, and 98 Mg of chemical oxygen demand.

Sodium-based scrubbing for sulfur oxides emissions control does not result in any incremental changes in the amount (dry weight) of solid wastes produced over that resulting from the particulate NSPS. However, the use of dual alkali flue gas desulfurization would produce a calcium sludge and increase the volume of solid waste to be disposed.

From preliminary information, application of sulfur oxides reduction catalysts to FCC units will result in negligible water and solid waste impacts over the baseline level.

1.2.3 Energy Impacts

The overall energy impacts of implementing Regulatory Alternatives II through IV are negligible. However, the electrical requirements would substantially increase for modified or reconstructed units with carbon monoxide combustion furnaces to employ sodium-based scrubbing. Electricity consumption would rise approximately 20 percent for these units to operate jet ejector venturis.

A more detailed analysis of environmental and energy impacts is presented in Chapter 7. A summary of these impacts for the regulatory alternatives is shown in Table 1-1.

1.3 ECONOMIC IMPACT

The nationwide capital and annual costs of Regulatory Alternatives II through IV are developed for new, modified, and reconstructed FCC units over the 5-year period from 1982 to 1986. These costs are based on the application of sodium-based flue gas desulfurization. Table 1-1 summarizes the economic impacts of these costs for each of the regulatory alternatives.

During this 5-year period, the nationwide cumulative capital costs of Regulatory Alternative II for the industry would be $72.1 million. The nationwide fifth-year annual cost to the industry under Alternative II would be $32.1 million. The nationwide 5-year cumulative capital costs for Regulatory Alternatives III and IV would each be $80.7 million. Nationwide annual costs of $35.3 million and $36.7 million would be incurred in the fifth year for Alternatives III and IV, respectively. The costs to industry of Alternatives II through IV are expected to be

Table 1-1. ASSESSMENT OF ENVIRONMENTAL AND ECONOMIC IMPACTS FOR EACH REGULATORY ALTERNATIVE CONSIDERED

Administrative action	Air impact	Water impact	Solid waste impact	Energy impact	Noise impact	Economic impact
Regulatory Alternative I	-4*	0	0	0	0	0
Regulatory Alternative II	+2*	-2*	-1*	-1*	-1*	-2*
Regulatory Alternative III	+3*	-2*	-1*	-1*	-1*	-2*
Regulatory Alternative IV	+4*	-2*	-1*	-1*	-1*	-2*
Delayed Standards	-4*	0	0	0	0	0
No Standards	-4*	0	0	0	0	0

KEY: + Beneficial impact
- Adverse impact
0 No impact
1 Negligible impact

2 Small impact
3 Moderate impact
4 Large impact

* Short-term impact
** Long-term impact
*** Irreversible impact

significantly lower through application of sulfur oxides reduction catalysts.

Economic analysis indicates that the impacts of Alternatives II through IV are small based on the use of flue gas desulfurization. Expected price increases in refined products to account for the costs of the regulatory alternatives are less than 0.40 percent for new, modified, and reconstructed units with flue gas desulfurization. Expected price increases would be less for sulfur oxides reduction catalysts. A detailed economic analysis is presented in Chapter 9.

2. INTRODUCTION

2.1 BACKGROUND AND AUTHORITY FOR STANDARDS

Before standards of performance are proposed as a Federal regulation, air pollution control methods available to the affected industry and the associated costs of installing and maintaining the control equipment are examined in detail. Various levels of control based on different technologies and degrees of efficiency are expressed as regulatory alternatives. Each of these alternatives is studied by EPA as a prospective basis for a standard. The alternatives are investigated in terms of their impacts on the economics and well-being of the industry, the impacts on the national economy, and the impacts on the environment. This document summarizes the information obtained through these studies so that interested persons will be able to see the information considered by EPA in the development of the proposed standard.

Standards of performance for new stationary sources are established under Section 111 of the Clean Air Act (42 U.S.C. 7411) as amended, hereinafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which "... causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect,"... the degree of emission reduction achievable which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions that apply to the process of establishing standards of performance.

1. EPA is required to list the categories of major stationary sources that have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

   a. 25 percent of the listed categories by August 7, 1980.

   b. 75 percent of the listed categories by August 7, 1981.

   c. 100 percent of the listed categories by August 7, 1982.

A governor of a State may apply to the Administrator to add a category not on the list or may apply to the Administrator to have a standard of performance revised.

2. EPA is required to review the standards of performance every four years and, if appropriate, revise them.

3. EPA is authorized to promulgate a standard based on design, equipment, work practice, or operational procedures when a standard based on emission levels is not feasible.

4. The term "standards of performance" is redefined, and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continuous and may include a low- or non-polluting process or operation.

5. The time between the proposal and promulgation of a standard under Section 111 of the Act may be extended to six months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impacts, and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. Second, stringent standards enhance the potential for long-term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal-burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems. Fifth, the standard-setting process should create incentives for improved technology.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area that falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term Best Available Control Technology (BACT), as defined in the Act, means

> ... an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Sections 111 or 112 of this Act. (Section 169(3))

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, Section 111(j) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require or an equivalent reduction at lower economic energy or environmental cost; (2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to the public health, welfare, or safety; (4) the governor of the State where the source is located consents; and (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to three years to meet the standards with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Adminstrator to list categories of stationary sources. The Administrator "... shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow.

Since passage of the Clean Air Act of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as: (1) the level of emission control (if any) already required by State regulations, (2) estimated levels of control that might be required from standards of performance for the source category, (3) projections of growth and replacement of existing facilities for the source category, and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which new source performance standards were promulgated or under development during 1977, or earlier, were selected on these criteria.

The Act amendments of August 1977 establish specific criteria to be used in determining priorities for all major source categories not yet listed by EPA. These are: (1) the quantity of air pollutant emissions that each such category will emit, or will be designed to emit; (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

The Administrator is to promulgate standards for these categories according to the schedule referred to earlier.

In some cases it may not be feasible immediately to develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, the types of facilities within the source category to which the standard will apply must be determined. A source category may have several facilities that cause air pollution, and emissions from some of these facilities may vary from insignificant to very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, the nonair quality health and environmental impacts, and the energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for developing standards is to identify the best technological system of continuous emission reduction that has been adequately demonstrated. The standard-setting process involves three principal phases of activity: (1) information gathering, (2) analysis of the information, and (3) development of the standard of performance.

During the information-gathering phase, industries are queried through a telephone survey, letters of inquiry, and plant visits by EPA representatives. Information is also gathered from many other sources, and a literature search is conducted. From the knowledge acquired about the industry, EPA selects certain plants at which emission tests are conducted to provide reliable data that characterize the pollutant emissions from well-controlled existing facilities.

In the second phase of a project, the information about the industry and the pollutants emitted is used in analytical studies. Hypothetical "model plants" are defined to provide a common basis for analysis. The model plant definitions, national pollutant emission data, and existing State regulations governing emissions from the source category are then used in establishing "regulatory alternatives." These regulatory alternatives are essentially different levels of emission control.

EPA conducts studies to determine the impact of each regulatory alternative on the economics of the industry and on the national economy, on the environment, and on energy consumption. From several possibly applicable alternatives, EPA selects the single most plausible regulatory alternative as the basis for a standard of performance for the source category under study.

In the third phase of a project, the selected regulatory alternative is translated into a standard of performance, which, in turn, is written in the form of a Federal regulation. The Federal regulation, when applied to newly constructed plants, will limit emissions to the levels indicated in the selected regulatory alternative.

As early as is practical in each standard-setting project, EPA representatives discuss the possibilities of a standard and the form it might take with members of the National Air Pollution Control Techniques Advisory Committee. Industry representatives and other interested parties also participate in these meetings.

The information acquired in the project is summarized in the Background Information Document (BID). The BID, the standard, and a preamble explaining the standard are widely circulated to the industry being considered for control, environmental groups, other government agencies, and offices within EPA. Through this extensive review process, the points of view of expert reviewers are taken into consideration as changes are made to the documentation.

A "proposal package" is assembled and sent through the offices of EPA Assistant Administrators for concurrence before the proposed standard is officially endorsed by the EPA Administrator. After being approved by the EPA Administrator, the preamble and the proposed regulation are published in the Federal Register.

As a part of the Federal Register announcement of the proposed regulation, the public is invited to participate in the standard-setting process. EPA invites written comments on the proposal and also holds a public hearing to discuss the proposed standard with interested parties. All public comments are summarized and incorporated into a second volume of the BID. All information reviewed and generated in studies in support of the standard of performance is available to the public in a "docket" on file in Washington, D. C.

Comments from the public are evaluated, and the standard of performance may be altered in response to the comments.

The significant comments and EPA's position on the issues raised are included in the "preamble" of a "promulgation package," which also contains the draft of the final regulation. The regulation is then subjected to another round of review and refinement until it is approved by the EPA Administrator. After the Administrator signs the regulation, it is published as a "final rule" in the Federal Register.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires an economic impact assessment with respect to any standard of performance established under Section 111 of the Act. The assessment is required to contain an analysis of: (1) the costs of compliance with the regulation, including the extent to which the cost of compliance varies depending on the effective date of the regulation and the development of less expensive or more efficient methods of compliance; (2) the potential inflationary or recessionary effects of the regulation; (3) the effects the regulation might have on small business with respect to competition; (4) the effects of the regulation on consumer costs; and (5) the effects of the regulation on energy use. Section 317 also requires that the economic impact assessment be as extensive as practicable.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and in terms of the control costs that would be incurred as a result of compliance with typical, existing State control regulations. An incremental approach is necessary because both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the economic impact from the cost differential that would exist between a proposed standard of performance and the typical State standard.

Air pollutant emissions may cause water pollution problems, and captured potential air pollutants may pose a solid waste disposal problem. The total environmental impact of an emission source must, therefore, be analyzed and the costs determined whenever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made for proposed standards. It is also essential to know the capital requirements for pollution control systems already placed on plants so that the additional capital requirements necessitated by these Federal standards can be placed in proper perspective. Finally, it is necessary to assess the availability of capital to provide the additional control equipment needed to meet the standards of performance.

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decisionmaking process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the United States Court of Appeals for the District of Columbia Circuit has held that environmental impact statements need not be prepared by the Agency for proposed actions under Section 111 of the Clean Air Act. Essentially, the Court of Appeals has determined that the best system of emission reduction requires the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry. On this basis, therefore, the Court established a narrow exemption from NEPA for EPA determination under Section 111.

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to Section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969." (15 U.S.C. 793(c)(1))

Nevertheless, the Agency has concluded that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, although not legally required to do so by Section 102(2)(C) of NEPA, EPA has adopted a policy requiring that environmental impact statements be prepared for various regulatory actions, including standards of performance developed under Section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section in this document is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as "... any stationary source, the construction or modification of which is commenced ..." after the proposed standards are published. An existing source is redefined as a new source if "modified" or "reconstructed" as defined in amendments to the general provisions of Subpart A of 40 CFR Part 60, which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416).

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under Section 111(d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e., a pollutant for which air quality criteria have not been issued under Section 108 or which has not been listed as a hazardous pollutant under Section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under Section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, Section 111 of the Act provides that the Administrator "... shall, at least every 4 years, review and, if appropriate, revise ..." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive, but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3.0 THE CATALYTIC CRACKING UNIT PROCESS AND POLLUTANT EMISSIONS

3.1 GENERAL

3.1.1 Introduction

Catalytic cracking is a petroleum refinery process in which hydrocarbon molecules in the presence of a catalyst are fractured or broken into smaller molecules. The catalyst allows the selective fracturing of heavy distillates (high molecular weight hydrocarbons) to light products (low molecular weight hydrocarbons). At many petroleum refineries, catalytic cracking is used to convert gas oils or residual feedstocks into gasoline and middle distillate blending stocks. Catalytic cracking is also used to produce light olefins (e.g., propylenes and butylenes) for gasoline alkylation and petrochemical production, and to produce cycle oils for use as blending components in heating oils and fuel oils.

Originally, hydrocarbon cracking was accomplished by a thermal process. However, this process did not produce sufficient quantities or qualities of desired products from the heavy feeds. The development of catalytic cracking allowed greater yields of gasoline blending stocks and other light products to be obtained while reducing the yield of heavy residuals or fuel oils. As a result of the improved yield and quality of products associated with the catalytic cracking process, catalytic cracking has almost completely replaced thermal cracking.

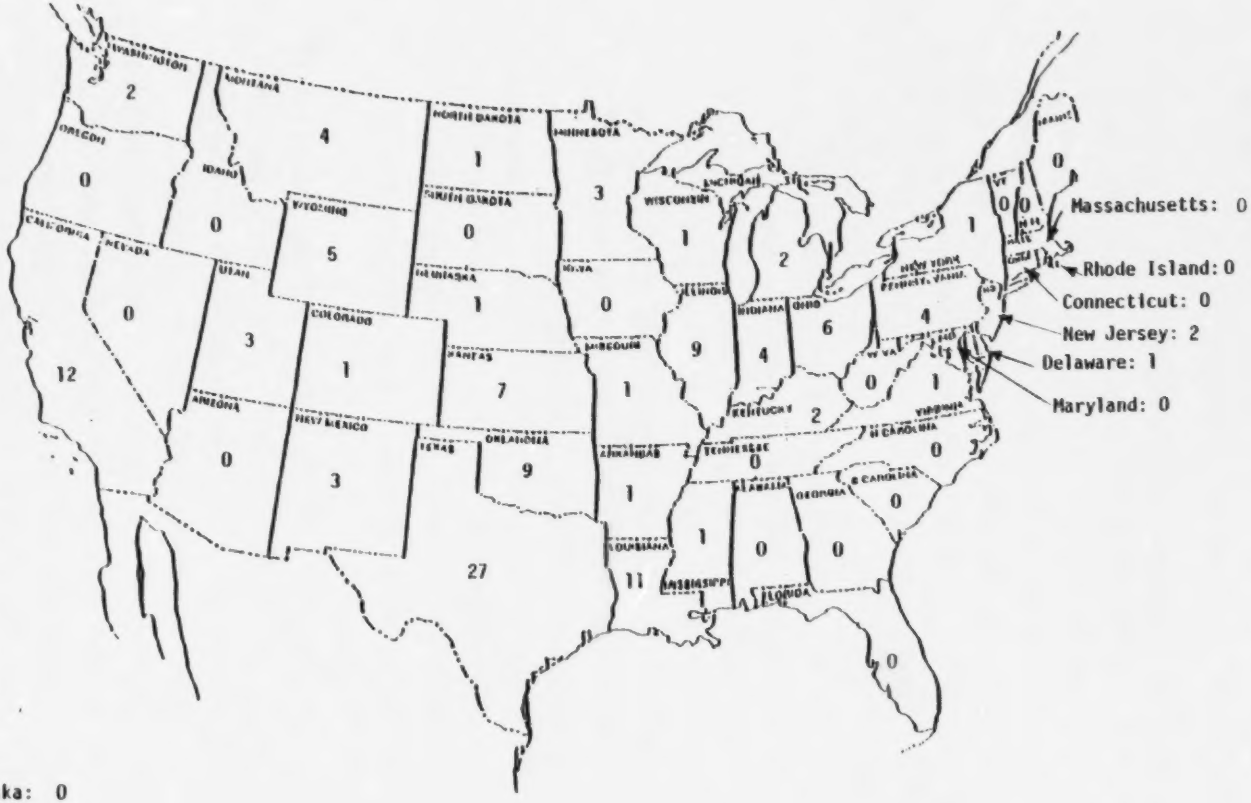
Fluidized catalytic cracking (FCC) involves the mixing of the feedstock with a stream of fine, suspended, catalyst particles (termed a "fluidized bed"). Upon completion of the cracking reactions, the cracked hydrocarbon vapors are separated from the catalyst. The cracked hydrocarbon vapors pass to a fractionating column where the vapors are distilled into the desired products. The spent catalyst, deactivated during the cracking process, is transferred to a regenerator. There, a carbon residue called coke, which deposits on the catalyst particles during the cracking reaction, is burned off. The reactivated catalyst is then recycled back to the catalytic cracking process. Sulfur oxides emissions result during catalyst regeneration from oxidation of sulfur compounds bound in the coke.

Two other types of catalytic cracking are also employed by the petroleum refining industry to produce gasoline blending stocks and other products. These are referred to as Thermofor catalytic cracking and Houdriflow catalytic cracking. In contrast to fluidized catalytic cracking, these processes use moving catalyst beds. As of January 1980 the Houdriflow process was used by 2 refineries and the Thermofor process was used by 15 refineries.[1] Since these processes are being gradually phased out of usage, the remainder of this document will deal only with fluid catalytic cracking.

3.1.2 Domestic Growth Trends in Fluid Catalytic Cracking

As of January 1980, FCC units were in operation at 126 petroleum refineries located in the United States (see Figure 3-1).[1] The FCC units have a combined throughput capacity of about 0.8×10^6 cubic meters of fresh feed per stream-day (0.8 Mm^3/sd). Although individual FCC unit throughput capacities range from 380 to 21,460 m^3/sd,[1] over 60 percent of the total FCC unit throughput capacity is attributable to units larger than 7,100 m^3/sd. The FCC units located in California, Louisiana, and Texas account for about 54 percent of the total throughput capacity.[1-10] A state-by-state listing of refineries operating FCC units is presented in Section 9.1.

Nationwide FCC processing capacity has increased from 0.6 Mm^3/sd in 1971 to 0.8 Mm^3/sd in 1980 in response to increasing gasoline demand.[1-10,11] Although total gasoline demand is expected to decline over the next 10 years,[11] total processing capacity growth is expected to continue because the FCC unit has the flexibility to process residual feeds, high sulfur gas oils, and synthetic (coal-derived) feeds. Also, the FCC unit is an important contributor to the high octane unleaded gasoline pool and distillate product inventory.[12,13,14]



WASHINGTON
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OREGON
0
CALIFORNIA
12
IDAHO
0
NEVADA
0
MONTANA
4
WYOMING
5
UTAH
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ARIZONA
0
COLORADO
1
NEW MEXICO
3
NORTH DAKOTA
1
SOUTH DAKOTA
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NEBRASKA
1
KANSAS
7
OKLAHOMA
9
TEXAS
27
MINNESOTA
3
IOWA
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MISSOURI
1
ARKANSAS
1
LOUISIANA
11
WISCONSIN
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MICHIGAN
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ILLINOIS
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INDIANA
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OHIO
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KENTUCKY
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TENNESSEE
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MISSISSIPPI
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ALABAMA
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PENNSYLVANIA
4
NEW YORK
1
VT
0
0
MAINE
0
Massachusetts: 0
Rhode Island: 0
Connecticut: 0
New Jersey: 2
Delaware: 1
Maryland: 0

Alaska: 0
Hawaii: 1

Figure 3-1. Statewide Distribution of Refineries with Fluid Catalytic Cracking Units As of January 1980[1]

Annual throughput capacity growth similar to that experienced between 1971 and 1980 is expected to yield a total FCC processing capacity of 0.93 Mm^3/sd in 1987. This growth will come from both new unit construction and additions to existing capacity. A more detailed discussion of industry growth is presented in Appendix E.

3.2 FLUID CATALYTIC CRACKING PROCESSES AND EMISSIONS

Up to 50 percent of the total crude oil input to a refinery may be ultimately processed in the FCC unit.[15] Figure 3-2 shows a generalized flow diagram illustrating the relationship between the FCC unit and other processes at a petroleum refinery. FCC feedstocks are derived from the distillation of crude oil and from other refinery process units. Heavy gas oil from the atmospheric and vacuum distillation units are typically charged to the FCC unit. Other sources of gas oil are thermal cracking, lube oil extraction and dewaxing, coking, and deasphalting processes. Residual feedstocks, such as vacuum and atmospheric distillation tower bottoms, are becoming a more important FCC unit feedstock source. The FCC unit feedstocks are usually blended with recycle oil, a stream of partially cracked hydrocarbons from the FCC fractionator, before being charged to the FCC.[16]

3.2.1 Fluid Catalytic Cracking Unit Process Equipment

An FCC unit consists of three basic sections: reactor, regenerator, and fractionator. Figure 3-3 presents a diagram of a generalized FCC unit. Variations in the design of FCC units exist throughout the petroleum refining industry, but basic product yields and operating characteristics are similar.

3.2.1.1 Reactor. Cracking reactions and catalyst/product separation take place in the reactor section of the FCC unit. The reactor section in a modern FCC unit usually consists of a riser reactor and a separator vessel which contains a catalyst disengager and a steam stripper.

Preheated feedstocks are blended with recycle oil from the fractionator and injected into a fluidized stream of regenerated catalyst near the bottom of the riser reactor. The catalyst temperature ranges from approximately 590 to 680°C, and the catalyst to feedstock mass ratio ranges from 4 to 10.[17] The cracking reactions begin as the hot, regenerated catalyst contacts and vaporizes the feed. As the vaporized

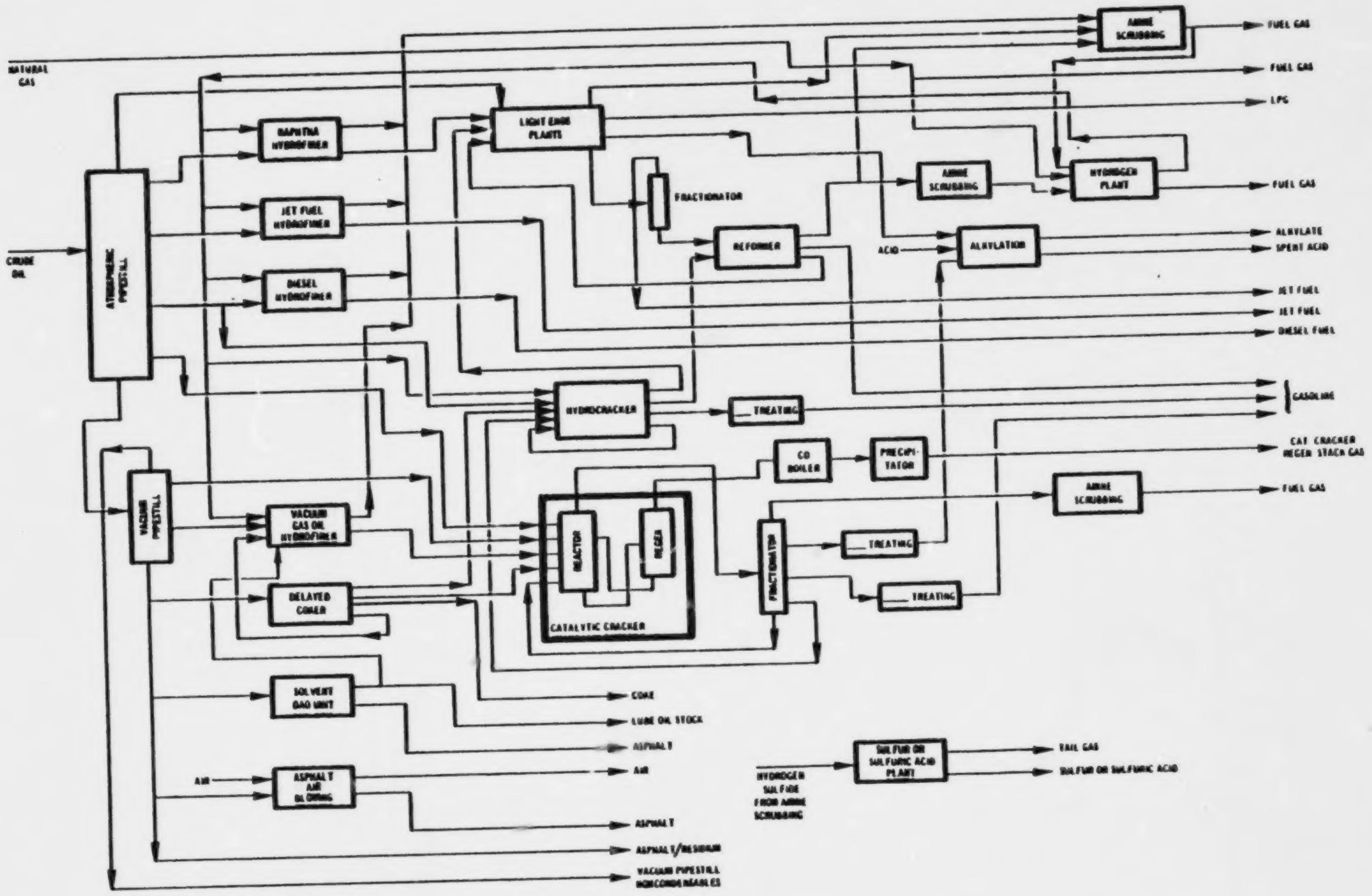
NATURAL GAS
CRUDE OIL
ATMOSPHERIC PIPESTILL
VACUUM PIPESTILL
NAPHTHA HYDROFINER
JET FUEL HYDROFINER
DIESEL HYDROFINER
VACUUM GAS OIL HYDROFINER
DELAYED COKER
SOLVENT DAO UNIT
AIR
ASPHALT AIR BLOWING
LIGHT ENDS PLANTS
FRACTIONATOR
REFORMER
HYDROCRACKER
TREATING
REACTOR
REGEN
CATALYTIC CRACKER
CO BOILER
PRECIPI-TATOR
FRACTIONATOR
TREATING
TREATING
AMINE SCRUBBING
AMINE SCRUBBING
AMINE SCRUBBING
HYDROGEN PLANT
ACID
ALKYLATION
SULFUR OR SULFURIC ACID PLANT
HYDROGEN SULFIDE FROM AMINE SCRUBBING
FUEL GAS
FUEL GAS
LPG
FUEL GAS
ALKYLATE
SPENT ACID
JET FUEL
JET FUEL
DIESEL FUEL
GASOLINE
CAT CRACKER REGEN STACK GAS
FUEL GAS
TAIL GAS
SULFUR OR SULFURIC ACID
COKE
LUBE OIL STOCK
ASPHALT
AIR
ASPHALT
ASPHALT/RESIDUUM
VACUUM PIPESTILL NONCONDENSABLES

Figure 3-2. Basic Flow Diagram of Petroleum Refinery Showing Location of Catalytic Cracking Unit.[18]

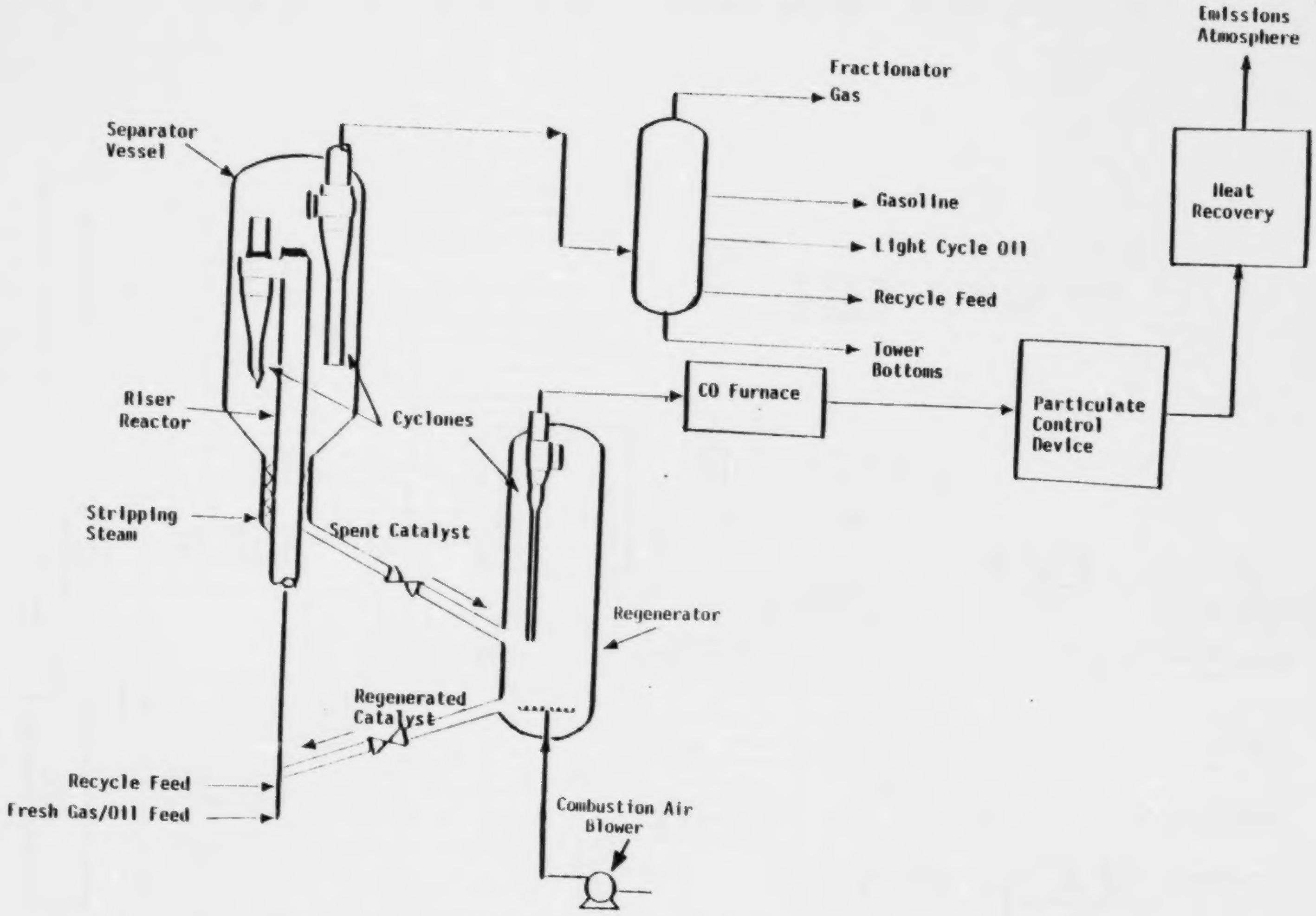
Emissions
Atmosphere
Fractionator
Gas
Separator
Vessel
Gasoline
Light Cycle Oil
Recycle Feed
Tower
Bottoms
Heat
Recovery
CO Furnace
Particulate
Control
Device
Riser
Reactor
Cyclones
Stripping
Steam
Spent Catalyst
Regenerator
Regenerated
Catalyst
Recycle Feed
Fresh Gas/Oil Feed
Combustion Air
Blower

Figure 3.3. Schematic of a Fluid Catalytic Cracking Unit[19]

hydrocarbons and catalyst particles flow upward through the riser reactor to the separator vessel, the hydrocarbons are cracked into lighter product molecules. The cracking reaction is endothermic, so the reacting mixture cools as it rises to the separator vessel. During the cracking process in the riser, the catalyst rapidly loses its activity. This occurs as high molecular weight aromatic and sulfur compounds, originally present in the feed, are preferentially adsorbed on catalyst surfaces where they react to form coke.[20] Deactivation of the catalytic cracking catalyst also occurs through the absorption of nitrogen and metal compounds.[15]

The separator vessel is designed to separate or disengage the catalyst particles from the cracked hydrocarbon vapors rapidly to minimize secondary reactions.[21,22] Multiple-stage cyclones installed inside the separator vessel remove most of the catalyst fines from the cracked hydrocarbon vapors (products). The products and the remaining entrained catalyst fines exit overhead to the fractionator. The coke-laden catalyst particles fall through a steam stripper in the separator vessel where additional entrained light hydrocarbons are displaced from the void spaces around the catalyst particle using steam as the displacing agent.[15,23] Both steam and hydrocarbons are then routed overhead with the products to the fractionator. Stripped catalyst is transferred to the regenerator to renew catalyst cracking activity and to generate heat for the cracking reaction.[24,25]

3.2.1.2 Regenerator. Coke, which deposits on the catalyst, blocks active cracking sites on the catalyst surface. Consequently, coke deposition reduces catalyst cracking activity. To renew catalyst activity, coke deposits are burned off the catalyst in the regenerator. The combustion products (flue gases) are primarily carbon monoxide (CO), carbon dioxide (CO_2), and water vapor. Sulfur oxides (SO_x) and nitrogen oxides (NO_x) are also formed due to oxidation of sulfur and nitrogen compounds bound in the coke.

Upon entering the regenerator, the spent catalyst particles from the reactor are suspended in a fluidized bed that is maintained at elevated temperatures. An air compressor (blower) injects a regulated amount of air into the regenerator vessel to fluidize the catalyst particles and to sustain combustion of the coke. Combustion gases resulting from catalyst regeneration pass through multiple-stage cyclones before leaving the regenerator. These cyclones, located within the regenerator, recover catalyst particles which become entrained in the regenerator flue gas during regeneration. These cyclones are generally considered process equipment.

The flue gases are vented from the multiple-stage cyclones and the regenerator through a pressure control valve. Normally, the flue gases are passed through air pollution control, heat recovery, and in some cases, power recovery equipment before discharge to the atmosphere. To comply with Federal, State, or local air pollution regulations, many existing FCC unit regenerators are equipped with electrostatic precipitators (ESP) for final removal of catalyst fines from the flue gases. A carbon monoxide combustion furnace or boiler is often used to control carbon monoxide emissions and to recover waste heat. In some installations, FCC regenerator flue gases pass through turbines to recover some energy from the flue gas. The recovered energy may be used to generate electricity. New FCC unit regenerators are required to meet new source performance standards (NSPS) for particulates (1.0 kg/1,000 kg coke burn-off) and carbon monoxide (500 vppm). These standards were promulgated March 8, 1974 (40 CFR 60.102, 40 CFR 60.103).

Catalyst coke is oxidized in conventional regeneration using an amount of combustion air that is insufficient for complete combustion to occur. This results in coke on regenerated catalyst (CRC) levels ranging from 0.1 to 0.6 weight percent[15,25] and in the generation of large quantities of carbon monoxide. Carbon monoxide flue gas concentrations from these units can be about 10 volume percent, representing a carbon dioxide/carbon monoxide ratio of about 1.0.[26,27] These large quantities of carbon monoxide are generated in the lower portion of the regenerator fluidized bed (dense bed) and pass through the upper portion of the fluidized bed (dilute-phase) and internal cyclones. The flue gases are then vented to pollution control equipment and to the atmosphere. Temperatures in the regenerator are about 590°C to 680°C. If excess oxygen is available within the regenerator, the carbon monoxide undergoes exothermic combustion in the dilute phase or internal cyclones, causing large temperature excursions and possible damage to the catalyst, cyclones, and auxiliary equipment. Carbon monoxide combustion furnaces are often used with conventional regenerators to combust carbon monoxide in a controlled manner outside the regenerator vessel.[17]

The latest regeneration techniques can reduce CRC to about 0.02 percent and flue gas CO content to about 0.05 percent (500 vppm). The two methods used to achieve this improvement include high temperature regeneration (HTR) and catalytically promoted carbon monoxide combustion. In HTR, combustion takes place within the regenerator dense bed. As the name implies, the regenerator dense bed and dilute phase temperatures are higher than in conventional regenerators. The energy released in the combustion of CO to CO_2 causes this temperature increase. The dense bed temperature is near 700°C, and the dilute phase temperature is 730°C to 745°C, although both can be as high as 760°C during HTR operation.[15,27] The advantages of this technique are more complete catalyst regeneration, lower catalyst inventory, better heat recovery within the regenerator and low carbon monoxide emissions. In catalytically promoted carbon monoxide combustion, catalysts promote and confine the combustion of carbon monoxide to the regenerator dense bed. This results in efficient heat transfer and minimizes high temperature excursions and subsequent equipment damage due to dilute phase afterburning.[28] It also permits existing units with metallurgical constraints to achieve high regeneration efficiencies through partial carbon monoxide combustion. The regenerator dense bed temperature is at least 670°C to 700°C, and the dilute phase temperature is 680°C to 720°C.[28,29] Promoters also yield low CRC ratios and give benefits similar to those derived from HTR.[30]

The activity of all catalysts, especially zeolite catalysts, is affected by the CRC.[25] Since large residual coke deposits inhibit catalyst activity, the low CRC obtained with HTR or carbon monoxide promoters results in improved product yields, reduced coke formation, and improved unit profitability.[30,31] Since complete carbon monoxide combustion occurs within the regenerator and the NSPS for carbon monoxide emissions can be met through the use of HTR or carbon monoxide combustion promoters, carbon monoxide combustion furnaces are not required.

3.2.1.3 Fractionator. Product vapors, steam, and some catalyst fines passing through the separator vessel cyclones are vented from the FCC unit to the fractionator. Within the fractionator, the vapors are separated into gases, catalytic gasoline, and light and heavy cycle oils. These products are sent to various areas within the refinery for further processing. Most of the entrained catalyst fines entering the fractionator settle to the bottom of the fractionator as a sludge. The catalyst sludge in some refineries is removed and mixed with the liquid recycle for reinjection into the riser reactor.[16] Fresh catalyst is added periodically to the FCC unit to make up for catalyst losses to the atmosphere and products.

3.2.2 Factors Affecting Sulfur Oxides Emissions from FCC Regenerators

The coke which deposits on the FCC catalyst during normal operations primarily contains carbon, hydrogen, nitrogen, and sulfur. Sulfur oxides emissions result when the sulfur that is contained in the coke is oxidized in the regenerator during coke burn-off. Thus, the operating parameters which directly or indirectly affect the sulfur content of the coke and the amount of coke burned off in a given period of time ultimately affect sulfur oxides emissions. The quantity of sulfur oxides emissions from the FCC unit regenerator can vary considerably with feedstock quality, regeneration mode, catalyst type, and operating conditions.

3.2.2.1 Feedstock Quality. The sulfur content of the FCC feed is the most important factor affecting sulfur oxides emissions from the FCC unit regenerator. The amount of sulfur in an FCC feed directly influences coke sulfur and thus, regenerator sulfur oxides emissions. A high sulfur feed may thus be generally expected to yield higher sulfur oxides emissions than a low sulfur feed since more sulfur will be found in the coke.

The amount of sulfur in a feedstock which ends up as coke sulfur depends on the source of the feedstock. The correlation presented in Figure 3-4 is derived from pilot plant data and shows a relationship between feed sulfur and coke sulfur content for feedstocks from various crude oils. At equivalent levels of feed sulfur, different feeds can yield different levels of coke sulfur, and thus different sulfur

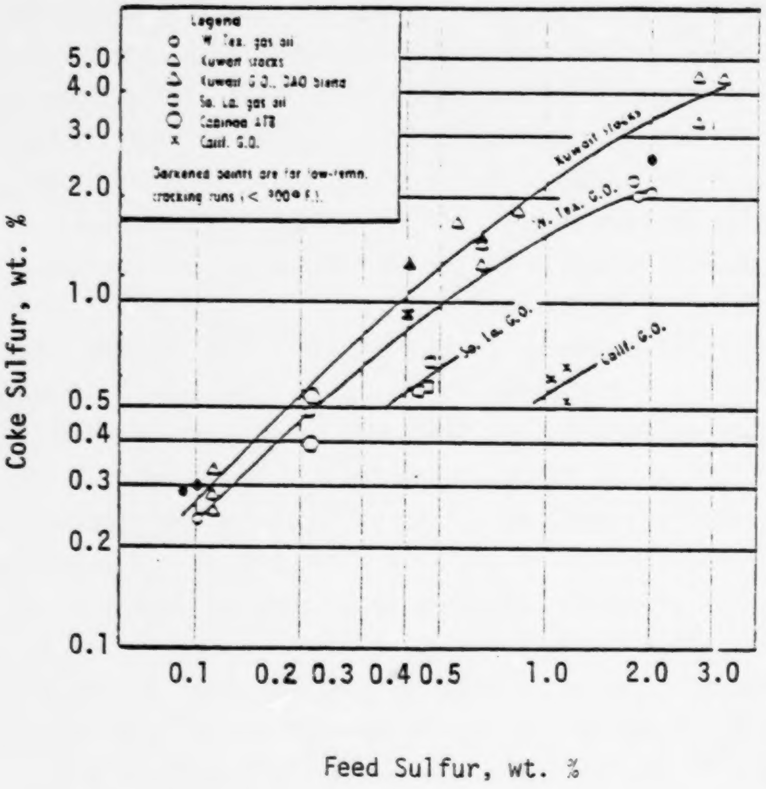

Figure 3-4. Relationship Between Feed Sulfur and Coke Sulfur[33]

oxides emissions.[32] As shown in Figure 3-4, at 1.0 percent feed sulfur, California gas oil produces a coke containing approximately 0.55 weight percent sulfur; West Texas gas oils produce approximately 1.5 weight percent coke sulfur; and feeds derived from Kuwait stocks produce 2.2 weight percent coke sulfur. Regenerator flue gas concentrations of sulfur oxides may vary from about 400 ppm by dry volume (vppm) to more than 1,700 vppm for units processing these gas oils.[33]

This variation in levels of coke sulfur is related to the coke forming tendency of the FCC feed and to the molecular form in which the sulfur is bound in the hydrocarbon molecules. Certain sulfur-bearing hydrocarbon molecules, called thiophenes, preferentially form coke on the FCC catalyst during the cracking reactions. Other sulfur-bearing molecules tend to crack into hydrogen sulfide and other light hydrocarbons. The hydrogen sulfide is vented with the products to the fractionator, leaving less sulfur to form on the catalyst. Thus, the relative quantity and molecular structure of the sulfur-bearing hydrocarbon determines the amount of sulfur in coke.[32]

FCC feedstock sulfur content is approximately equal to the sulfur content of the crude oil from which the gas oil is derived.[34] A range of expected sulfur contents for FCC feeds may be derived by identifying the crude slates from which the feeds originate. Given the unstable nature of world crude oil supplies, it is difficult to identify possible future refinery crude slates. An analysis of historical trends and general crude sulfur content is required to bracket the potential range of FCC feed sulfur characteristics.

In 1978, "sweet" crude oil (sulfur content less than 0.5 weight percent) processing accounted for over 53 percent of the total crude processing volume.[35] The typical sulfur content of crude oil from mid-continental United States oil fields, such as those in Oklahoma and Louisiana, is about 0.3 weight percent.[36] Other oil fields which also yield crude oil with this or lower average sulfur contents include those in Africa, Western Europe, and the Far East (Indonesia).[37] It is expected that this heavy reliance on sweet stocks will continue, but decrease slightly from 54 to 49 percent through 1982.[38]

Refiners select and use crude stocks based on overall economics and supply considerations. The demand for lower quality crude stocks (high sulfur content, low gravity) is expected to increase as supplies of low sulfur crude oil become more expensive and less available. As a result, the type of crude oil processed by U.S. refineries is expected to change. It is estimated that the average sulfur content of the total crude processed in the U.S. will rise to 1.28 weight percent in 1985 and 1.3 weight percent in 1990. In 1976, the average crude oil sulfur content was 0.8 weight percent.[39] Some refiners expect their future FCC feeds to have a sulfur content near or above 2.0 weight percent.[34,40,41,42] This is especially true if the highest sulfur feedstocks from the Middle East (4.6 weight percent) and Mexico (5 weight percent) are utilized.

Residue and reduced crude processing are also expected to become important as refiners try to maximize useful liquid yields from each unit volume of crude oil. Several companies have developed an FCC-type unit, known as a heavy oil cracker (HOC), which can handle these residual feeds.[43,44] Asphalt residual treating (ART), a recently developed FCC-like process, improves the quality of residual and heavy crude feedstocks by removing carbon residue and other impurities.[55] The sulfur content of most of these residual feeds may exceed 2.0 weight percent.

FCC feed sulfur contents may thus range from less than 0.3 weight percent to a value between 2.5 weight percent and 5.0 weight percent. Regenerator flue gas sulfur oxides concentrations may range from less than 200 vppm to over 2,500 vppm for these feeds.[33]

Contaminant metals are also present in all FCC unit feedstocks to some degree. Concentrations are dependent on the crude oil source, boiling fraction, and the degree of pretreating. The metals deposit on the catalyst and tend to nonselectively catalyze undesirable reactions.[45] These reactions result in a decrease in catalyst activity and an increase in gas and coke yields, thus greater sulfur oxide emissions.

3.2.2.2 Regeneration Mode. Regeneration mode refers to the regeneration techniques commonly used by refiners. As described in Section 3.2.1.2, refiners employ conventional regeneration, high temperature regeneration, and catalytically promoted carbon monoxide combustion regeneration to renew catalyst cracking activity. Each regeneration technique affects how completely coke is burned off the catalyst particles.

The efficiency of coke burn-off directly affects coke yields, conversion, gasoline yields, circulation rates, feed preheat requirements, and sulfur oxides emissions. Regeneration efficiency is measured by determining the weight percent carbon remaining on the regenerated catalyst, CRC. CRC affects sulfur oxides emissions through its association with coke production. Efficiently regenerated catalysts, and catalysts with low CRC complete feed cracking reactions with less catalyst coke production than catalysts with high CRC. This is because coke on regenerated catalysts promotes undesirable coke forming reactions during cracking.[30] Reducing CRC thus reduces coke production and sulfur oxides emissions.

For a given FCC feed and feed rate, sulfur oxides emissions from FCC regenerators using high temperature or carbon monoxide-promoted regeneration may thus be less than the sulfur oxides emissions from conventional regenerators.

3.2.2.3 Operating Conditions. Fluid catalytic cracking units have the flexibility to produce a wide variety of products from a wide variety of feedstocks. Yields of certain products may be optimized by adjusting the operating conditions within the reactor and regenerator sections. Unit operations depend upon market demands, emission limitations, and processing capabilities elsewhere in the refinery.

In optimizing FCC operations for different product requirements, the amount of coke produced for each unit volume of feed (coke yield) and the rate at which coke is produced (coke make rate) may vary. For example, coke yield (as weight percent of the feed) generally increases as the light product yield from a given FCC feedstock is maximized. Similarly, coke make rate may be increased by increasing unit throughput at constant coke yield. Both of these operational changes increase emissions of sulfur oxides from an FCC unit regenerator.

Refiners sometimes recycle a portion of heavy cycle oils to increase yields of other products. Maximum distillate production is obtained, for example, when refiners recycle heavy cycle oil. Conversely, maximum gasoline yield is obtained when distillate products are recycled. Due to higher conversion of the feedstock to products, recycling may result in increased coke production and therefore, increased sulfur oxides emissions.[46] With current zeolite catalyst technology, distillate recycle is rarely used.[23]

3.2.3 Emissions from FCC Regenerators

Pollutant emission rates can be estimated for FCC regenerators by using emission factors described in AP-42.[47] These emission factors generally represent average emission levels and thus do not reflect the complete range of emissions from individual FCC units. The range of FCC pollutant emission rates may be determined by considering the typical ranges in feed sulfur, coke yield, and FCC capacity, and by evaluating the stoichiometric relationships involved in regenerating FCC catalyst.

Catalyst regeneration is similar to solid fuel combustion in a boiler. This is discussed in more detail in Chapter 4. Flue gas compositions and flow rates may be calculated by determining the coke composition and formation rate and by calculating the amount of air required to oxidize the coke. Coke formation rates vary depending on the FCC and how it is operated. Coke yield, expressed as a weight percentage of the feed, varies between 4 weight percent and 6.5 weight percent for many FCC feeds.[48] The feed density is assumed to be 900 kg/m^3.

Coke is composed of carbon, hydrogen, sulfur, and small amounts of nitrogen and metals. Coke may typically contain from 4 to 12 percent hydrogen.[15,23,25] The sulfur content of the coke may range from less than 0.1 to 5 weight percent or more, depending on the type of feed processed. Assuming that the nitrogen and metals content of coke is negligible, carbon would represent the balance of coke composition.

Certain regenerator combustion air inlet and flue gas compositions must also be assumed when calculating emissions. Inlet air to the regenerator may contain from 76.0 to 78.8 volume percent nitrogen, 20 volume percent oxygen, and from 1.2 to 4.0 volume percent water. The water vapor content is typical for a Gulf Coast location.[15] Emission calculations are discussed below.

The air flow rates are determined by calculating the amount of air required to burn the coke that is formed on the catalyst. The coke burn-off rate assumed for this calculation is 5 weight percent of the fresh feed rate. Coke sulfur content is specified by using the correlation between feed sulfur and coke sulfur presented in Figure 3-5. This correlation[34] is derived from pilot plant data such as presented in Figure 3-4. Data points showing the relationship between feed sulfur and coke sulfur for pilot and commercial FCC unit operations have been plotted onto Figure 3-5 to show that this correlation is representative of feed sulfur-coke sulfur relationships for many common FCC feedstocks.

Coke hydrogen content is assumed to be 4 weight percent and carbon is assumed to represent the balance. Regenerator combustion air is assumed to contain 78.8 volume percent nitrogen, 20 volume percent oxygen, and 1.2 volume percent water. Flue gas compositions of carbon monoxide and oxygen are assumed to be 0.05 and 2.0 volume percent, respectively.

From these assumptions, air flow rates entering and exiting the FCC regenerator are determined stoichiometrically. The results of this emissions analysis are plotted in Figure 3-6. A separate analysis of emissions from HOC's and other FCCU-like processes, calculated as described above, is presented in Appendix F. Data points showing the relationship between feed sulfur and sulfur oxides emissions for pilot and commercial FCC unit operations have been plotted onto Figure 3-6 to show that the calculated model plant emissions are representative of actual FCC unit operations.

A sensitivity analysis was performed to determine the effect of different input values on calculated FCC sulfur oxides emissions. Results of this analysis show that calculated FCC emissions are relatively insensitive to all input values except coke sulfur content when sulfur oxides emissions are reported in a concentration or mass per unit of coke burn-off format.[54] Model plants are discussed in Section 6.0.

3.2.3.1 Sulfur Oxides. If the above conditions are applied to FCC units which range in throughput capacity from 800 m^3/sd to 21,500 m^3/sd and on feed sulfur contents which range from 0.1 weight percent to 3.5 weight percent, a wide range of FCC sulfur oxides emissions is identified. Flue gas concentrations may range from less than 200 vppm to approximately 3,000 vppm. Sulfur oxides mass emission rates may range from approximately 7.5 kg/hr to 4,700 kg/hr.

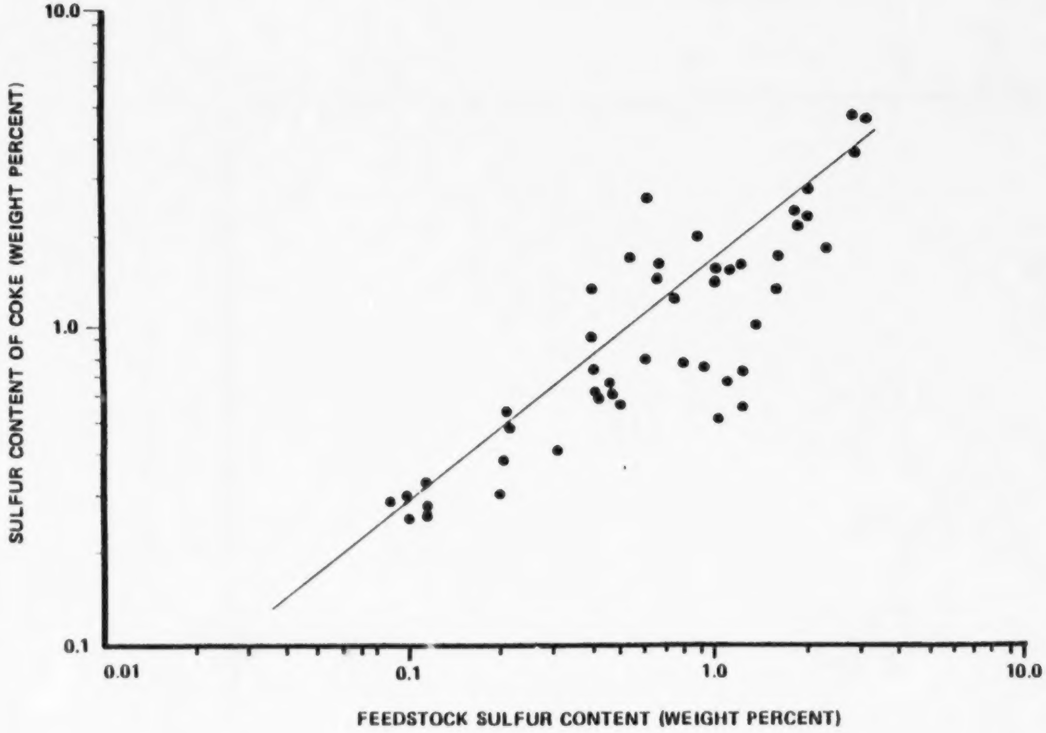

Figure 3-5. Comparison Between Pilot Plant Feedstock Sulfur/Coke Sulfur Correlation and Actual FCC Unit Data [34]

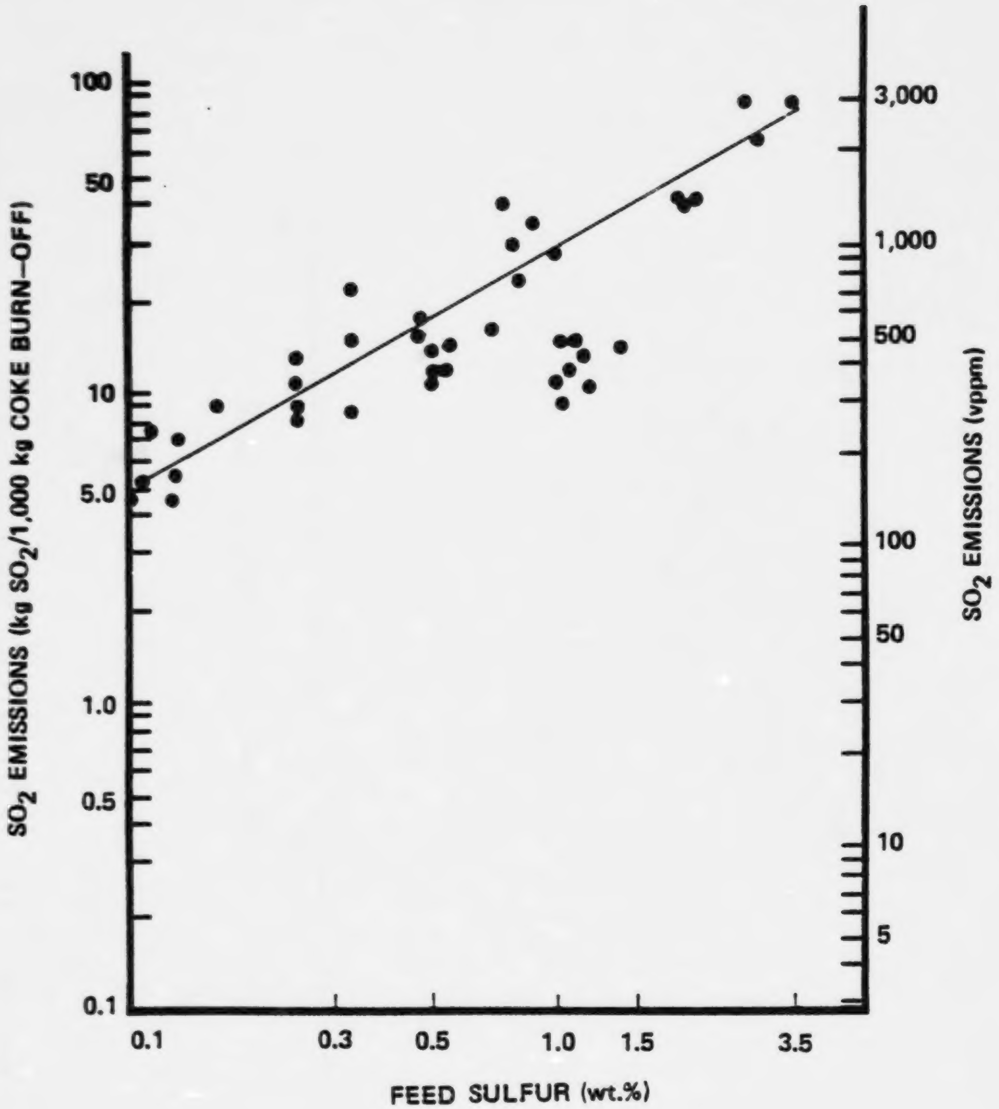

Figure 3-6. Comparison between Model Plant, Pilot Plant, and Actual FCC Unit Sulfur Oxides Emissions Data.

A portion of sulfur oxides is present as SO_3, as a result of the reaction:[49]

$$SO_2 + 1/2\ O_2 \longrightarrow SO_3.$$

Few data exist which adequately specify the concentrations of SO_3 in the regenerator flue gas. Estimates have ranged from 0.1 to 60 volume percent of the total sulfur oxides. Typical SO_3 levels may be less than 10 volume percent.[25,49] Recent articles suggest that at high flue gas excess oxygen contents, SO_3 emissions may be as significant as SO_2.[50] In view of the limited information available on SO_3 emissions from FCC regenerators, the calculated sulfur oxides emissions from the FCC regenerators are reported as SO_2 emissions.

3.2.3.2 Particulate Matter Emissions. Particulate matter in the flue gas essentially consists of catalyst fines and some of the impurities contained in the charging stock. The emission factor for uncontrolled particulate emissions spans a range from 0.27 to 0.98 kg/m^3 fresh feed (6 kg/1,000 kg of coke burn-off to 22 kg/1,000 kg coke burn-off).[47] Particulate emissions from new sources must meet the NSPS level of 1 kg/1,000 kg of coke burn-off.

3.2.3.3 Carbon Monoxide Emissions. Carbon monoxide results from the incomplete combustion of catalyst coke. New sources are required to control carbon monoxide flue gas concentrations to less than 500 vppm. This is accomplished through the use of special regeneration techniques or through the combustion of the carbon monoxide in a waste heat incinerator. New units are assumed to use modern regeneration techniques described in Section 3.2.1.2 to control carbon monoxide emissions to 500 vppm.

3.2.3.4 Nitrogen Oxides Emissions. Nitrogen oxides are formed in the FCC regenerator by two mechanisms. In the first, nitrogen in the combustion air combines with oxygen in a temperature-dependent reaction to form various nitrogen oxides. In the second mechanism, nitrogen present in the coke combines with oxygen to form nitrogen oxides. Thermal nitrogen oxides formation is thought to be low at typical regenerator temperatures (675-735°C). Therefore, the majority of nitrogen oxides is assumed to result from nitrogen present in the coke. The major nitrogen oxide specie is nitric oxide.[15,25] Nitrogen oxides emissions from conventional regeneration are approximately

20 vppm. Nitrogen oxides emissions are generally less than 200 vppm from high temperature regenerators and are, on average, 550 vppm for conventional regeneration FCC units which utilize promoter catalysts. Use of sulfur oxides reduction catalysts may increase nitrogen oxides emissions beyond these levels.[51] Effective technologies for the control of nitrogen oxides emissions have not yet been proven commercially.

There are no applicable Federal regulations for controlling nitrogen oxides emissions from FCC units.

3.2.3.5 Volatile Organic Compounds (VOC) Emissions. Emissions of VOC are dependent on the type of regeneration. The VOC emissions from conventional regeneration are less than 500 vppm before the carbon monoxide boiler. After the carbon monoxide boiler, the VOC concentration is less than 10 vppm. The VOC emissions from HTR are less than 10 vppm.[52] There are no applicable Federal regulations governing VOC emissions from FCC units.

3.2.3.6 Other Pollutants. Other pollutants from FCC units include cyanides as HCN and ammonia as NH_3. The concentrations of both these pollutants is about 10 ppm for high temperature regenerators or after carbon monoxide combustion furnaces used on conventional regenerators.[52]

3.3 EMISSIONS UNDER EXISTING REGULATIONS

Nationwide emissions of sulfur oxides from existing FCC units are a function of nationwide FCC processing capacity, State sulfur oxides emission regulations, existing FCC sulfur oxides emission control systems, and feedstock quality.

Emissions may be estimated by assuming that the FCC unit is emitting sulfur oxides at a level equal to the State emission limits. This is a simple calculation requiring knowledge of the emission limits and unit operating capacities when the sulfur oxides mass limitation is expressed on a throughput basis.

The formats of State regulations applicable to sulfur oxides emissions from the FCC unit, however, are inconsistent and vary from concentration limits (e.g., 2,000 vppm) to mass limitations. In some States, the entire refinery falls under a "bubble," and an emission limit is set for the whole refinery rather than specifically for the FCC regenerator. Table 3-1 summarizes State and local regulations for

Table 3-1. STATE AIR REGULATIONS FOR SO_x EMISSIONS APPLICABLE TO FLUID CATALYTIC CRACKING UNIT REGENERATORS

EPA		SO_x Emission Regulation		
Region	State	Existing Sources	New Sources	Comments
II	New Jersey	2,000 vppm	2,000 vppm	emission rate (mass units) based on stack height, gas velocity, and gas temperature
	New York	NAAQS[a]	NAAQS	
III	Delaware	NAAQS	NAAQS	
	Pennsylvania	500 vppm	500 vppm	
	Virginia	2,000 vppm	2,000 vppm	process regulations[b]
IV	Kentucky	2,000 vppm	2,000 vppm	
	Mississippi	2,000 vppm	500 vppm	process regulations
V	Illinois	2,000 vppm	2,000 vppm	
	Indiana	181-681 kg/hr	Source[c] Specific	Source Specific, SIP regulation (approval pending)
	Indianapolis	28.2 kg/hr	Source Specific	to be modified to NAAQS using computer model and process parameters
	Michigan	NAAQS	NAAQS	
	Wayne County	300 vppm		process regulation corrected to 50 percent excess air
			NSPS[d] or existing	County will adopt most stringent regulation for new sources

[a] NAAQS - National Ambient Air Quality Standard for SO_2 at ground level.

[b] Process regulations - General regulations applicable to many processes.

[c] Source specific regulations - regulations applicable to specific FCC units.

[d] NSPS - New Source Performance Standard when developed.

Table 3-1. STATE AIR REGULATIONS FOR SO_x EMISSIONS APPLICABLE TO FLUID CATALYTIC CRACKING UNIT REGENERATORS (Continued)

EPA Region	State	SO_x Emission Regulation Existing Sources	New Sources	Comments
	Minnesota	NAAQS	NAAQS	
	Ohio	0.62-3.0 kg/1000 kg feed		
			Source Specific	Source specific regulation (includes SIP regulation)
	Wisconsin	NAAQS	NAAQS	
VI	Arkansas	NAAQS	NAAQS	
	Louisiana	2,000 vppm	2,000 vppm	
	New Mexico	4,545 kg/day		total SO_x emissions from refinery
			10 kg/100 kg SO_x released	refineries releasing 4,545 kg and 27,272 kg/day of sulfur in process; 90 percent control
			2 kg/100 kg SO_x released	refineries releasing 27,272 kg/day of sulfur in process; 98 percent control
VI	Oklahoma	NAAQS	NAAQS	
	Texas	NAAQS		individual county regulations
			BACT[a]	source specific
VII	Kansas	NAAQS	NAAQS	
	Missouri	NAAQS		
			NAAQS NSPS	if ambient standard is exceeded, facilities with 454.5 kg SO_x/hr will be required to reduce emissions

[a] BACT - Best available control technology.

Table 3-1. STATE AIR REGULATIONS FOR SO_x EMISSIONS APPLICABLE TO FLUID CATALYTIC CRACKING UNIT REGENERATORS (Concluded)

EPA Region	State	SO_x Emission Regulation Existing Sources	 New Sources	Comments
	Nebraska	SO_x emissions cannot exceed 1971 emissions	NSPS	also AP-42 emission estimates
VIII	Colorado	2.0 kg/m^3 processed	0.86 kg/m^3 processed	total SO_2 emissions from refinery
	Montana	Ambient	Ambient, NSPS	
	Utah	Ambient	NSPS	source specific regulation being developed for plants in nonattainment areas
	Wyoming	Ambient	NSPS	
IX	California	Ambient	Ambient	
	SCAQMD[a]	2,000 vppm	0.82 kg/m^3 feed	applicable 7/1/81
			0.38 kg/m^3 feed	applicable 7/1/85
	BAAQMD[b]	1,000 vppm	BACT	
	Hawaii	Ambient	Ambient	
X	Washington	1,000 vppm	1,000 vppm, NSPS	

[a] South Coast Air Quality Management District.

[b] Bay Area Air Quality Management District.

FCC regenerators. For many of these regulatory formats, calculation of nationwide emissions requires knowledge of the FCC regenerator exhaust gas flow rates. This flow rate may change on a weekly basis and is affected by the feedstock quality, catalyst type, and other process variables. This makes calculation of nationwide emissions difficult. In addition, Lowest Achievable Emissions Rate (LAER) provisions may apply to some of the affected FCC regenerators. LAER limits FCC regenerator emissions to 300 vppm. It is unclear which, if any, of the affected FCC regenerators would be subject to these requirements.[19]

Nationwide emissions of sulfur oxides from FCC regenerators can be approximated by using the EPA emission factors published in AP-42.[47] The AP-42 emission factors for FCC unit regenerators are averaged values obtained from emission tests of typical FCC unit operations. These tests represent the level of sulfur oxides emission control currently achieved by FCC units to meet most State and local sulfur oxides regulations. The emission factor for sulfur oxides emissions from FCC regenerators is 1.413 kg/m^3 of fresh feed.[47] For a total nationwide FCC fresh feed capacity of 800,000 m^3/sd,[53] the nationwide January 1980 baseline emission of sulfur oxides from FCC units is 413,000 Mg/year. The feed sulfur/sulfur oxides relationship illustrated in Figure 3-6 is used to estimate sulfur oxides emissions from the model plants discussed in Section 6.0.

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4.0 EMISSION CONTROL TECHNIQUES

4.1 INTRODUCTION

There are four basic techniques applicable to controlling sulfur oxides emissions from fluidized catalytic cracking (FCC) unit regenerators:

(1) Flue gas desulfurization
(2) Feed hydrotreating
(3) FCC unit process changes
(4) Sulfur reduction catalysts

Flue gas desulfurization processes remove sulfur oxides from the flue gases vented from the FCC unit regenerator. The sulfur oxides are converted to a liquid waste, solid waste, or salable product. Sulfur oxides emissions from the regenerator can be controlled indirectly by using hydrotreating to reduce the sulfur content of the FCC unit feedstock. FCC unit process changes can reduce the amount of coke deposited on the catalyst and, subsequently, reduce the amount of sulfur oxides vented from the regenerator. An emerging technique for controlling regenerator sulfur oxides emissions involves the use of special FCC unit sulfur oxides reduction catalysts. Each of the techniques is discussed in the following sections.

4.2 FLUE GAS DESULFURIZATION

Flue gas desulfurization (FGD) involves the removal of sulfur oxides from a waste gas stream. Two broad categories are used to classify FGD processes: (1) disposable FGD systems (often referred to as "throwaway" systems) and (2) regenerable FGD systems. Disposable FGD systems use processes where all waste streams are discarded. Regenerable FGD systems use processes where the waste stream is treated for regeneration of the sorbent and often the recovery of salable sulfur compounds such as elemental sulfur and sulfuric acid.

Over 100 different FGD processes have been proposed.[1] However, many of these processes have not been developed beyond the laboratory or pilot plant phase. Currently, there are six FGD systems that are in commercial use in the United States. The six systems and their applications are summarized in Table 4-1.

Six FGD systems have been selected as candidates for application to FCC unit regenerators. The FGD systems selected are:

- Sodium-based FGD systems
- Calcium-based FGD systems
- Double alkali FGD systems
- Wellman-Lord FGD systems
- Citrate FGD systems
- Spray drying FGD systems

Sodium-based FGD systems are currently being used to control sulfur oxides emissions from FCC unit regenerators. A citrate scrubber is currently under construction for FCC unit regenerator application. The calcium-based, double alkali, and spray drying FGD systems are currently operating or being installed at industrial and utility boiler locations in the United States. Flow rates and characteristics for flue gases from FCC unit regenerators are similar to flue gases from industrial and utility boilers.[2] Similarities between boilers and FCC unit regenerators are discussed in Section 4.2.1. Other FGD systems not discussed here, such as magnesium oxide, have only been installed at a limited number of industrial/utility boilers.

4.2.1 Applicability of FGD Systems to FCC Regenerators

Sodium-based scrubbing systems have been effectively applied to seven FCC regenerators at five refineries to control both particulate and sulfur oxides emissions. These seven FCC regenerators with sodium-based scrubbers represent 11 percent of nationwide FCC processing capacity.[110] The performance characteristics of sodium-based scrubbers are discussed in Section 4.2.2. Citrate scrubbers have been demonstrated in utility boiler applications. A citrate scrubber is currently under construction for an FCC unit regenerator application. Performance characteristics for this scrubber system are discussed in Section 4.2.7. Application of the calcium-based, double alkali, Wellman-Lord, and spray drying FGD systems presently used on utility and industrial

TABLE 4-1. FGD SYSTEM COMMERCIAL APPLICATIONS

FGD Process	Number of Operational FGD Systems		
	FCC Unit Regenerators	Industrial Boilers[a]	Utility Boilers[a]
Sodium based	7	119	3
Calcium based	-	2	28
Double alkali	-	21	-
Spray drying	-	4[b]	10[b]
Magnesium oxide	-	-	1
Wellman-Lord	-	3[c]	4[c]
Citrate	1[e]	1[a,d]	-

[a] Reference 3.

[b] This represents the number of contracts signed for spray drying systems as of February 1981. See Reference 2.

[c] Reference 4.

[d] As of November 1979, 1 industrial boiler application was planned.

[e] Under construction.

boilers may depend on similarities between FCC regenerator and boiler flue gases. FCC regenerator flue gas compositions are dictated by the catalyst coke composition. Boiler flue gas compositions depend on the properties of the boiler fuel.

The coke formed on the FCC catalyst is a carbonaceous material similar to the coal used in solid fuel-fired industrial boilers. Approximate elemental analyses of catalyst coke and bituminous coal are shown in Table 4-2. The catalyst coke is burned off the catalyst during regeneration by adding air to the regenerator. The regeneration process is thus similar to the combustion processes which take place in boilers. Given the similarities between catalyst coke and other solid fuels, the combustion process which takes place in the FCC regenerator may be expected to yield flue gases which are similar to those derived from coal-fired boilers.

A comparison between FCC regenerator flue gases and industrial boiler flue gases is presented in Table 4-3.[10] FCC regenerator flue gas compositions were determined from a survey of State emission test data, stoichiometric relationships, and from AP-42 emission factors.[9] Boiler flue gas parameters are calculated values for a field erected watertube boiler which burns high sulfur Eastern United States coal.[10] As suggested by the information presented, the ranges in concentration of most FCC regenerator flue gas constituents overlap the boiler flue gas concentrations. FGD systems installed on FCC regenerators will thus experience similar inlet concentrations as boiler FGD systems.

The primary difference between FCC regenerator flue gases and boiler flue gases is the particulate emissions. Boiler particulate emissions are primarily fly ash, while catalyst fines comprise the majority of regenerator particulate emissions. Both fly ash and catalyst fines are erosive and may cause abnormal wear in an improperly designed or operated FGD system.[11,12]

Hydrocarbon emissions from FCC regenerators may be higher than those from boilers, especially if they are uncontrolled (see Table 4-3). The effects of hydrocarbon concentration on scrubber operation are not

Table 4-2. ANALYSIS OF ELEMENTAL COMPOSITIONS OF COKE AND COAL

	Composition (wt. %)	
Element	Catalyst Coke[5,6,7]	Selected U.S. Coals, Ash Free, Dry Basis[8]
Carbon	84.5 - 96.0	74.0 - 90.4
Hydrogen	4.0 - 12.0	4.8 - 5.7
Sulfur	0.0 - 4.5	0.3 - 4.0
Nitrogen	0.0 - 1.0	0.9 - 1.7
Other:		
Moisture	NA[a]	1.0 - 31.0
Volatile Matter	NA	17.7 - 49.3
Ash	NA	3.3 - 11.7

[a] Not available.

Table 4-3. COMPARISON OF FLUE GAS ANALYSES FOR FCC REGENERATORS AND INDUSTRIAL COAL-FIRED BOILER[a]

	FCC Regenerator	Industrial Coal-Fired Boiler[b]
Unit Capacity	800-21,500 m^3/sd[c]	52 MW
Flue Gas Flow Rate (Nm^3/min)	280-8,500[d]	2,700
Flue Gas Temperature (°C)	230-420[e,f]	210
Flue Gas Composition		
N_2 vol. %[n]	81-84[g,h]	81.0
O_2 vol. %[n]	0.1-8.0[i,g]	4.2
CO_2 vol. %[n]	9-16[j,f]	14.6
CO vol. %[n]	0-6.9[f,i]	0
Particulates (g/m^3)[o]	0.4-1.5[k]	9.6
SO_x (vppm)[o]	120-1,600[e,l]	2,800
NO_x (vppm)[o]	64-250[k]	410
Hydrocarbons (g/m^3)[o]	1.0[k]	0
Moisture vol. %	10-23[m,f]	7.5

[a] Uncontrolled emissions.

[b] Estimated for high sulfur Eastern U.S. coal (3.54 wt. % S) assuming 120 percent theoretical air for the boiler. See Reference 10.

[c] Reference 14.

[d] Reference 15.

[e] Reference 16.

[f] Reference 17.

[g] Reference 18.

[h] Reference 19.

[i] Reference 20.

[j] Reference 21.

[k] Calculated from AP-42 emission factor for 9500 m^3/min air flow and 21,500 m^3/sd. See Reference 9.

[l] Reference 22.

[m] Reference 23.

[n] Dry basis.

[o] Wet basis.

known; presently operating FCC regenerator FGD systems may remove some hydrocarbons from the flue gas stream.[13]

Other differences in flue gas compositions are minor and are not expected to invalidate the applicability of FGD systems to FCC regenerators.

There are two specific areas of concern in applying FGD systems to FCC regenerator flue gas. FCC units are very durable and can often operate continuously from 2 to 4 years. Therefore, any FGD system for an FCC unit application should have a similar on-line reliability. Also, because of potentially significant SO_3 emissions, the selection of a regenerable system may be limited to ones that can tolerate sulfates.

The scrubbing systems identified here for application to FCC units have had varying degrees of on-line reliability to date. To ensure acceptable FGD reliability for FCC regenerator applications certain precautions should be exercised. Plugging of the capture system can be minimized through the use of venturi collectors (not tray towers or packed towers) and a continuous wash of the mist eliminator. Spare capture modules should also be used so maintenance can be performed on-line. Other portions of the FGD systems that have potential maintenance problems routinely have redundant equipment. Sodium-based FGD systems in use on FCC units have very high reliability due to the use of redundant equipment. Some of these scrubbers have run for over 38 months without a shutdown.[116]

4.2.2 Sodium-Based FGD Systems[24]

4.2.2.1 Process Description. Sodium-based FGD processes are capable of achieving high sulfur oxides removal efficiencies over a wide range of inlet sulfur oxides concentrations. However, these processes consume a premium chemical and produce an aqueous waste for disposal which contains sodium sulfite and sulfate salts. Sodium-based FGD systems currently use an aqueous solution of sodium hydroxide (NaOH), sodium bicarbonate ($NaHCO_3$), or sodium carbonate (NA_2CO_3) to absorb sulfur oxides from the flue gases. Sodium alkali sorbents are highly reactive relative to calcium-based sorbents. Also, the reactant liquid is a clear solution rather than a slurry because of the high solubility of sodium salts. The sulfur oxides absorption reactions which take place are:

$$2NaOH + SO_2 \longrightarrow Na_2SO_3 + H_2O$$

$$2NaHCO_3 + SO_2 \longrightarrow Na_2SO_3 + H_2O + CO_2$$

$$Na_2CO_3 + SO_2 \longrightarrow Na_2SO_3 + CO_2$$

$$Na_2SO_3 + SO_2 + H_2O \longrightarrow 2NaHSO_3$$

Simultaneously some sodium sulfite reacts with the oxygen in the flue gases to produce sodium sulfate:

$$Na_2SO_3 + 1/2O_2 \longrightarrow Na_2SO_4$$

The resulting product is primarily a sodium sulfite, bisulfite, and sulfate solution which is removed from the process for disposal.

4.2.2.2 System Design. A generalized flow diagram for the sodium-based FGD system as applied to the FCC unit regenerator is presented in Figure 4-1. This system may be described in terms of three basic processes:

(1) Reagent preparation
(2) Particulate removal and sulfur oxides absorption
(3) Waste preparation and disposal

The reagents used in FCC applications of sodium-based FGD systems are either sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3). Sodium systems currently in use on utility and industrial boilers employ sodium hydroxide, sodium carbonate, or sodium bicarbonate ($NaHCO_3$) as the sorbent. Storage silos are required for solid or liquid reagents; mixing tanks are required for solid reagents.

For FCC-applied sodium-based scrubbing systems, particulate removal and sulfur oxides absorption occur in a venturi scrubber. Two scrubber designs, the jet ejector and high energy venturi scrubber, are in use on FCC units. Selection of venturi type depends upon the pressure of the flue gas exiting the regenerator.[13,26]

The jet ejector venturi scrubber, shown in Figure 4-2, consists of a spray nozzle and venturi throat. The scrubbing liquor, sprayed into the venturi through the nozzle at 513 to 925 kPa,[27] induces a draft, drawing regenerator flue gas into the scrubber. Thus, the jet-ejector venturi operates with negligible pressure drop. This type

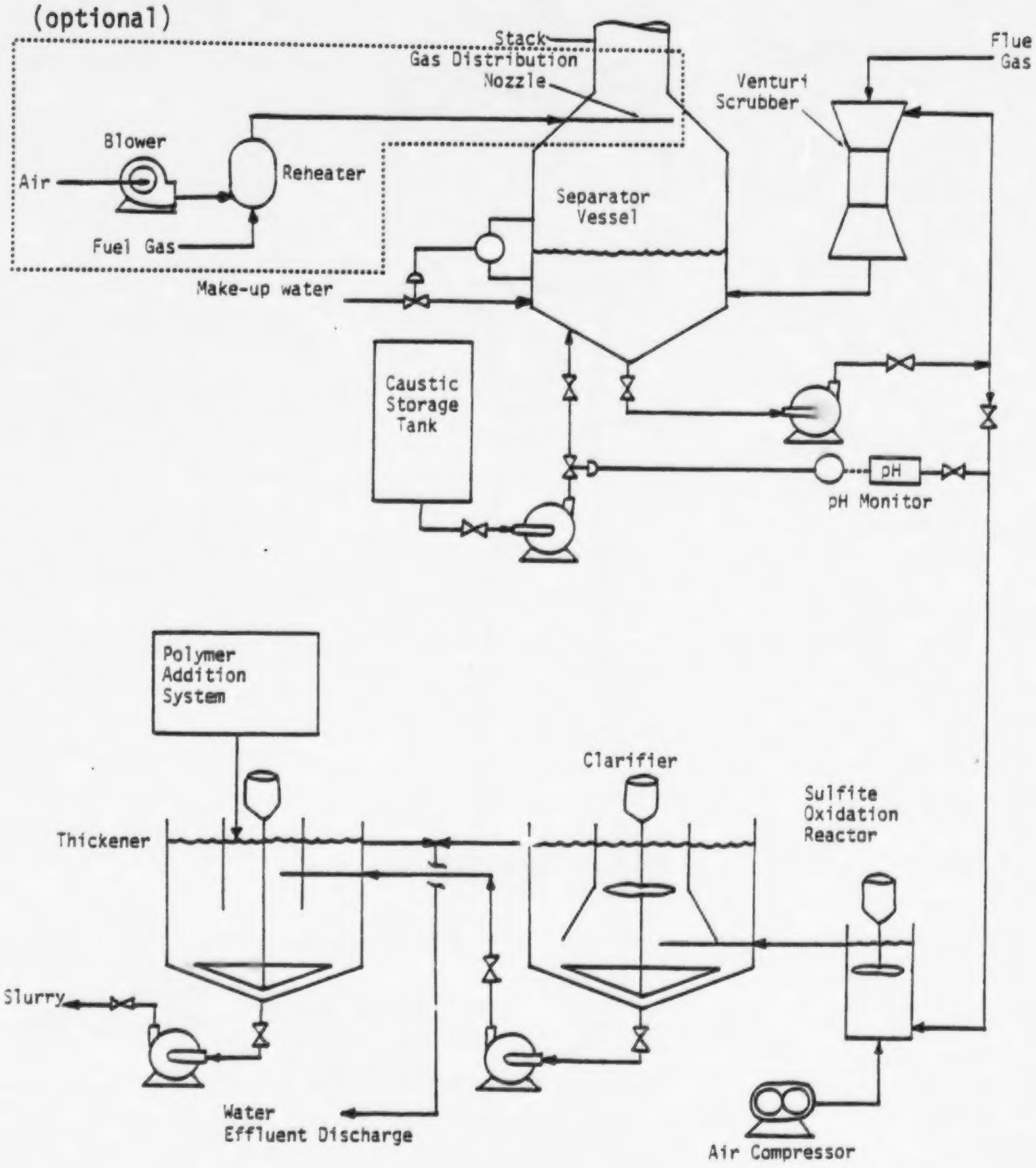
(optional)
Stack
Gas Distribution Nozzle
Flue Gas
Venturi Scrubber
Blower
Air
Reheater
Fuel Gas
Separator Vessel
Make-up water
Caustic Storage Tank
pH
pH Monitor
Polymer Addition System
Clarifier
Sulfite Oxidation Reactor
Thickener
Slurry
Water Effluent Discharge
Air Compressor

Figure 4-1. Process Layout of the Sodium-Based Venturi Scrubbing System Applied to FCC Regenerators[25]

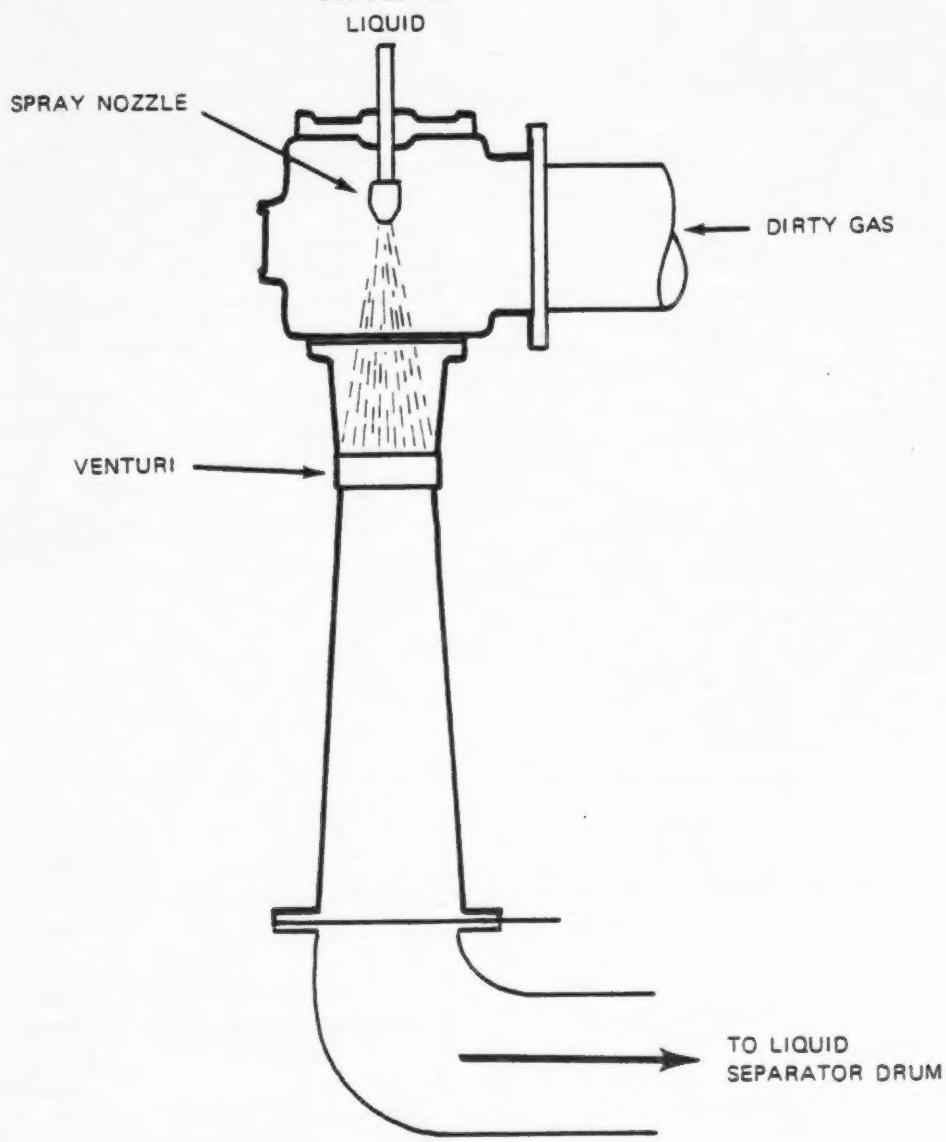
SCRUBBING LIQUID
SPRAY NOZZLE
DIRTY GAS
VENTURI
TO LIQUID SEPARATOR DRUM

Figure 4-2. Jet Ejector Venturi Scrubber

of venturi has been applied to existing FCC units with carbon monoxide boilers which cannot be backpressured to use a high energy venturi scrubber.[7] The high energy venturi scrubber, a wet-wall venturi, has been applied to two new FCC units with high temperature regeneration and an overall flue gas pressure drop of about 10.3 kPa. Typical liquid-to-gas (L/G) ratios for the jet ejector scrubber are 6.7 to 13.4 m^3 of scrubbing liquor per 1,000 m^3 of flue gas. Typical L/G ratios for the high energy venturi scrubber are 0.7 to 4.0 m^3/1,000 m^3 of flue gas.[12]

Sulfur oxides removal occurs by reaction between the sodium-based scrubbing liquor and the sulfur oxides in the gas stream. Particulate removal occurs by inertial impaction of the scrubbing liquor with the entrained particulates. These solid-liquid and gas-liquid mass transfer interactions occur within the venturi scrubber. Contactors other than venturis are used in industrial and utility boiler applications. In these applications, the contactors operate at low pressure drops and are designed only for sulfur oxides control. A separate control device is usually required to control particulate emissions.

Gases from the venturi pass into a separator vessel. Here the flue gases are separated from entrained scrubbing liquor. The flue gases are directed to a stack, reheated if necessary, to maintain plume buoyancy, and vented to the atmosphere. The scrubbing liquor collected in the separator vessel is recirculated back to the venturi scrubber with a small purge stream sent to the wastewater treatment system.

Changes in flue gas flow rates are compensated for in the scrubber by altering the scrubbing liquor flow rate to maintain a constant L/G ratio. In the jet ejector venturi scrubber, the scrubbing liquor pressure at the spray nozzle affects the flue gas flow rate and the scrubbing liquor flow rate.[28]

As flue gas sulfur oxides react with the reagent in the scrubbing liquor, the pH of the liquor falls, reducing the sulfur oxides removal efficiency of the scrubbing system. To maintain scrubber efficiency and liquor pH between 6 and 7 as well as to minimize corrosion and erosion,[7,29] sodium carbonate, hydroxide, or bicarbonate is added to the scrubbing liquor.

A portion of the recirculating liquor is continuously removed from the scrubber system. This stream, consisting of collected particulate and spent scrubbing liquor (mostly sodium salts), is directed to oxidation and clarification tanks or ponds to reduce chemical oxygen demand and remove suspended particulates. The treated stream is then disposed to surface water, evaporative ponds, or injected into deep wells. Solid wastes are most commonly disposed in a landfill.[30]

4.2.2.3 Development Status. Sodium scrubbing systems are commercially available technologies. These systems have been applied to seven FCC unit regenerators at five petroleum refineries, and to 80 percent of the commercial industrial boilers with FGD equipment in the U.S.[31] Table 4-4 summarizes the location and performance of sodium-based FGD systems presently applied to FCC regenerators.

4.2.2.4 System Performance. A scrubber vendor claims that up to 95 percent reduction in sulfur oxides has been achieved by sodium-based scrubbers in actual FCC unit emission tests.[13] From available FCC unit performance test data summarized in Table 4-4 and found in Appendix C, a 97 percent removal efficiency was achieved on one FCC unit with an inlet SO_2 concentration of 280 ppm.[37] Scrubber sulfur oxides outlet concentrations of 9 to 100 vppm have been observed in other FCC tests (see Appendix C). Although designed to accommodate inlet sulfur oxides levels as high as 3,000 vppm, the performance of sodium-based scrubbers applied to FCC unit catalyst regenerators has not been assessed at high inlet sulfur oxides concentrations. Since model unit regenerator flue gas sulfur oxides concentrations are as high as 2,700 vppm, it is necessary to evaluate scrubber outlet concentrations under these conditions. Information on sodium-based scrubber operation at high sulfur oxides concentrations was obtained from EPA tests of coal-fired industrial boilers. FCCU catalyst regenerator flue gas is similar to the flue gases generated by fossil fuel-fired boilers in flow rate, temperature, and in the composition of nitrogen, oxygen, carbon dioxide, carbon monoxide, particulates, sulfur oxides, and nitrogen oxides. Thus, sulfur oxides control technologies applicable to fossil fuel-fired boilers are also applicable to FCCU catalyst regenerators.

Fossil fuel-fired boilers emit high concentrations of sulfur oxides when burning high sulfur fuels. At one facility EPA conducted

TABLE 4-4. PERFORMANCE DATA FOR OPERATING SODIUM-BASED FGD SYSTEMS ON FCC UNIT REGENERATORS

Refinery/ Location	Scrubber Type	Sorbent	Airflow Rate (Nm^3/min)	SO_2 Inlet Concentration (vppm)	SO_2 Outlet Concentration (vppm)	SO_2 Removal Efficiency (%)	Waste Disposal Method[a]	Reference
Exxon Bayway, NJ	Two Jet Ejector Venturis for one FCC Unit	Sodium-based	8,540[c]	NA	15[b,f,g]	NA	To Surface Water	15
Exxon Baton Rouge, LA (2 FCC Units)	One Jet Ejector Venturi System for Both FCC Units	Sodium-based	8,230[c]	NA	1.5-118	NA	To Surface Water	7, 32,33
Exxon Baytown, TX (2 FCC Units)	One Jet Ejector Venturi for Each FCC Unit	Sodium-based	3,520[c] 5,575[c]	660 1,010	8-36[g] 61[g]-90	94 94	To Surface Water	7, 34,35,36
Marathon Garyville, LA	High Energy Venturi	Sodium-based	3,700[d]	280-390[f]	9-27	93-97	To Surface Water	37,38
South-western[e] Corpus Christi, TX	High Energy Venturi	Sodium-based	1,740 1,890	N/A 150	3.7 7.5	N/A 95	To Surface Water	115

[a] Disposal following treatment for chemical oxygen demand (COD) and suspended solids.

[b] Calculated from mass emission rate.

[c] After CO boiler.

[d] High temperature regeneration (HTR).

[e] Scrubber start-up 12/80; unit has not yet been tested.

[f] Reported as total sulfur oxides.

[g] Dry.

a continuous monitoring program on a sodium-based scrubber system installed on a boiler that was burning coal with 3.25 to 3.73 weight percent sulfur. During a 2-day period in the testing, scrubber inlet sulfur dioxide concentrations ranged from about 1,670 to 2,760 vppm on an hourly basis. Outlet concentrations varied during this period from about 9 to 55 vppm, and represent emission reductions of up to 98 percent.[39] The performance of other sodium-based scrubbers on industrial boilers ranges from 80 to 98 percent control of sulfur dioxide at inlet concentrations ranging from 150 to 2,100 vppm.[40] Thus, sodium-based scrubbing systems will substantially reduce high flue gas sulfur dioxide concentrations and are therefore applicable over the expected range of FCCU catalyst regenerator sulfur dioxide emissions.

Venturi scrubbers installed on FCC regenerator flue gas streams also control particulate emissions. Tests performed at a new FCC regenerator show the unit to be in compliance with the new source performance standard for particulate emissions (1 kg/1,000 kg coke burn-off).[29] This unit employs a high energy venturi scrubber. Emissions from one FCC regenerator with a jet ejector scrubber system are well within the particulate new source performance standard (NSPS) although it is not a new source (see Appendix C for a summary of results).[15] In this case, State particulate emission limitations are well below the new source standard.

4.2.3 Calcium-Based FGD Systems[41]

4.2.3.1 Process Description. Calcium-based FGD systems use an aqueous slurry of insoluble calcium compounds to absorb sulfur oxides from the flue gases. Lime (calcium oxide, CaO) or finely ground limestone (calcium carbonate, $CaCO_3$) is mixed with water to form a slurry. The absorption of sulfur oxides by the slurry involves both gas-liquid and liquid-solid mass transfer. The chemistry is complex and involves many side reactions. The overall reactions are:

Lime

$$SO_2 + CaO + 1/2H_2O \longrightarrow CaSO_3 \bullet 1/2H_2O$$

$$SO_2 + 1/2O_2 + CaO + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

Limestone

$$SO_2 + CaCO_3 + 1/2H_2O \rightarrow CaSO_3 \bullet 1/2H_2O + CO_2$$

$$SO_2 + 1/2O_2 + CaCO_3 + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

The resulting product is a calcium sulfite and calcium sulfate precipitate, which is removed from the process for disposal.

4.2.3.2 System Design. A generalized flow diagram for a calcium-based FGD system is presented in Figure 4-3. The basic design of the system can be divided into four process components.

(1) Reagent preparation
(2) Sulfur oxides absorption
(3) Solids separation
(4) Solids disposal

The reagent preparation for calcium-based FGD systems used for utility boiler applications often consists of limestone crushing and grinding, and/or lime production. For an FGD system designed for the significantly lower flue gas flow rates typical of an industrial boiler or FCC unit regenerator, lime or preground limestone would probably be purchased and delivered to the facility. Thus, the reagent preparation system for an FCC unit regenerator application would consist of storage silos and either lime slaking or limestone slurrying equipment.

The absorption of sulfur oxides occurs in a gas-liquid contactor (often referred to as an "absorber"). Various types of contactors (e.g., venturi scrubbers, packed towers, spray towers) are used depending on the specific FGD system design. Gases from the absorber are vented to a stack. The absorber liquid effluent flows to a reaction vessel or hold tank where calcium sulfite and sulfate crystals precipitate. The hold tank is designed to provide adequate residence time for solids precipitation as well as for dissolution of the calcium reagents. A continuous effluent stream is pumped from the hold tank and circulated to the absorber.

A purge stream from the hold tank is sent to a solid-liquid separator to remove the solids from the system. Solids separation or dewatering can be accomplished using a variety of methods depending on the location of the disposal site and the method of disposal used. The solids content of the waste sludge from a calcium-based FGD system normally ranges from 30 to 85 percent by weight.

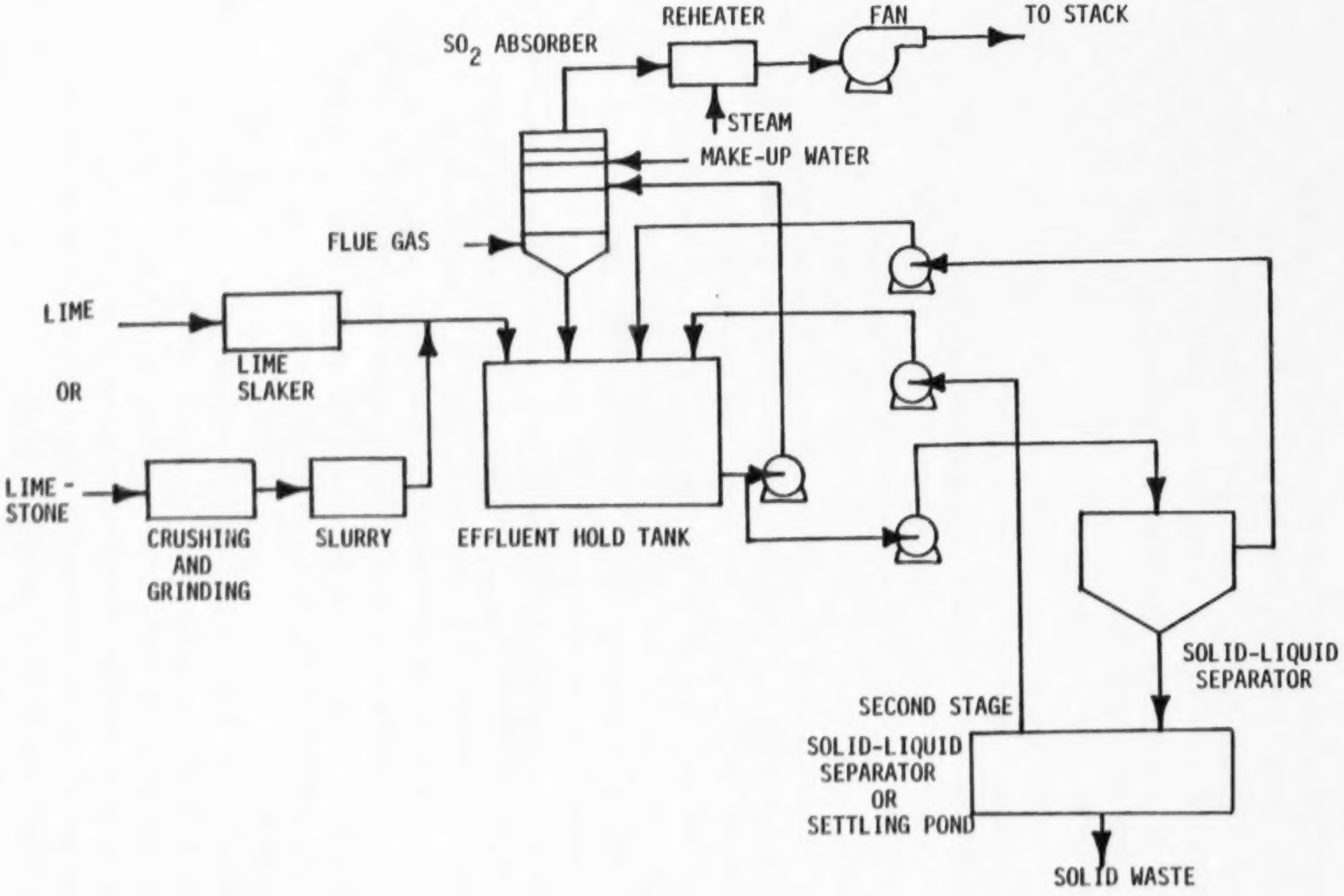
SO$_2$ ABSORBER
REHEATER
FAN
TO STACK
STEAM
MAKE-UP WATER
FLUE GAS
LIME
OR
LIME-STONE
LIME SLAKER
CRUSHING AND GRINDING
SLURRY
EFFLUENT HOLD TANK
SOLID-LIQUID SEPARATOR
SECOND STAGE
SOLID-LIQUID SEPARATOR OR SETTLING POND
SOLID WASTE

Figure 4-3. Process flow diagram for a typical calcium-based wet scrubbing system[42]

Sludge disposal is one of the major disadvantages of calcium-based FGD systems in comparison to other types of FGD systems. Dewatered sludge is generally sent to a pond or landfill for disposal. Some companies have attempted to process the waste sludge into building materials or other salable products, but additional developmental work remains.

4.2.3.3 Development Status. Both lime and limestone FGD systems are currently commercially available. Calcium-based FGD systems are the most common type of FGD systems used in the United States to control sulfur oxides emissions from utility coal-fired boilers. A recent survey reported that lime or limestone FGD systems were in operation at 28 facilities, under construction at 35 facilities, and being planned at 16 facilities. Calcium-based FGD systems have recently been installed at two industrial boiler locations in the United States (refer to Table 4-5). No calcium-based FGD systems have been installed on FCC unit regenerators.

4.2.3.4 System Performance. Calcium-based FGD systems have achieved sulfur oxides removal efficiencies of at least 90 percent for flue gas streams from coal-fired utility boilers[44] and at least 88 percent for flue gas streams from industrial boilers. Inlet sulfur oxides concentrations for industrial boilers may range from 200 to 2,000 ppm.[45] A summary of the design characteristics for operating and planned calcium-based FGD systems applied to industrial boilers is presented in Table 4-5.

4.2.4 Double Alkali FGD Systems[46]

4.2.4.1 Process Description. Double alkali FGD systems (also referred to as "dual alkali") use an aqueous sodium-based alkali solution to absorb sulfur oxides from the flue gases. A second calcium-based alkali solution is used to regenerate the active sodium solution. Although there are other types of double alkali processes which have been investigated, the sodium/calcium double alkali process is the most developed. The principal chemical reactions for a sodium/calcium double alkali system are:

Absorption

$$2NaOH + SO_2 \longrightarrow Na_2SO_3 + H_2O$$

$$Na_2CO_3 + SO_2 \longrightarrow Na_2SO_3 + CO_2$$

Table 4-5. SUMMARY OF COMMITTED CALCIUM-BASED SYSTEMS FOR U.S. INDUSTRIAL BOILERS AS OF MARCH 1978[43]

Company and Location	Scrubber Reagent, Vendor	Air Flow scm/m	Fuel		SO_2 Design Removal Efficiency %
			Type	% Sulfur	
Armco Steel, Middletown, OH	Lime, Koch Engineering	2,400	Coal	0.8	NA[a]
Carborundum Abrasives, Buffalo, NY	Lime, Carborundum Environmental Systems	850	Coal	2.2	95
Rickenbacker Air Force Base Columbus, OH	Lime/Limestone, Research Cottrell-Bahco	1,600	Coal	3.6	90
Bunge, Inc. Cairo, IL	Lime, Dravo Corp./National Lime Assoc.	1,250	Coal	3.0	94
Pfizer, Inc. East St. Louis, IL	Lime, Pfizer, Inc.	1,100	Coal	3.5	95

[a] Not available.

$$Na_2SO_3 + 1/2O_2 \longrightarrow Na_2SO_4$$

$$Na_2SO_3 + SO_2 + H_2O \longrightarrow 2NaHSO_3$$

Regeneration

$$Ca(OH)_2 + 2NaHSO_3 \longrightarrow Na_2SO_3 + CaSO_3 \bullet 1/2H_2O + 3/2H_2O$$

$$Ca(OH)_2 + Na_2SO_3 + 1/2H_2O \longrightarrow 2NaOH + CaSO_3 \bullet 1/2H_2O$$

$$Ca(OH)_2 + Na_2SO_4 + 2H_2O \longrightarrow 2NaOH + CaSO_4 \bullet 2H_2O$$

The sodium hydroxide (NaOH) solution is recycled in the process. The calcium sulfite and calcium sulfate precipitate is removed for disposal.

4.2.4.2 System Design. A generalized flow diagram for a double alkali FGD system is presented in Figure 4-4. In general, the double alkali FGD system uses technology common to sodium-based and calcium-based FGD systems.

The reagent preparation equipment consists of storage silos, lime slaker, and mix tanks. Absorption of sulfur oxides occurs in a gas-liquid contactor. The type of contactor varies depending on the FGD system design. Gases from the contactor are vented to a stack. A portion of the effluent is recirculated back to the contactor. The remainder of the effluent flows to a reaction vessel into which is added the calcium-based alkali solution. The reactor effluent is pumped to a thickener. There the precipitated calcium salts are separated from the solution. The regenerated NaOH solution is returned to the reagent hold tank. Sludge containing the calcium sulfite/sulfate solids is further concentrated in a vacuum filter to about 50 percent solids by weight. The solids are washed, generally with one or two displacement washes to recover sodium salts. The washed solids are then sent to a pond or landfill for disposal. The filtrate and wash water are recycled to the thickener.

4.2.4.3 Development Status. Several process vendors currently commercially offer double alkali FGD systems in the United States. Double alkali FGD systems are presently operating or planned for use at 10 industrial boiler sites. Table 4-6 summarizes double alkali FGD systems applied to industrial boilers. The smallest application

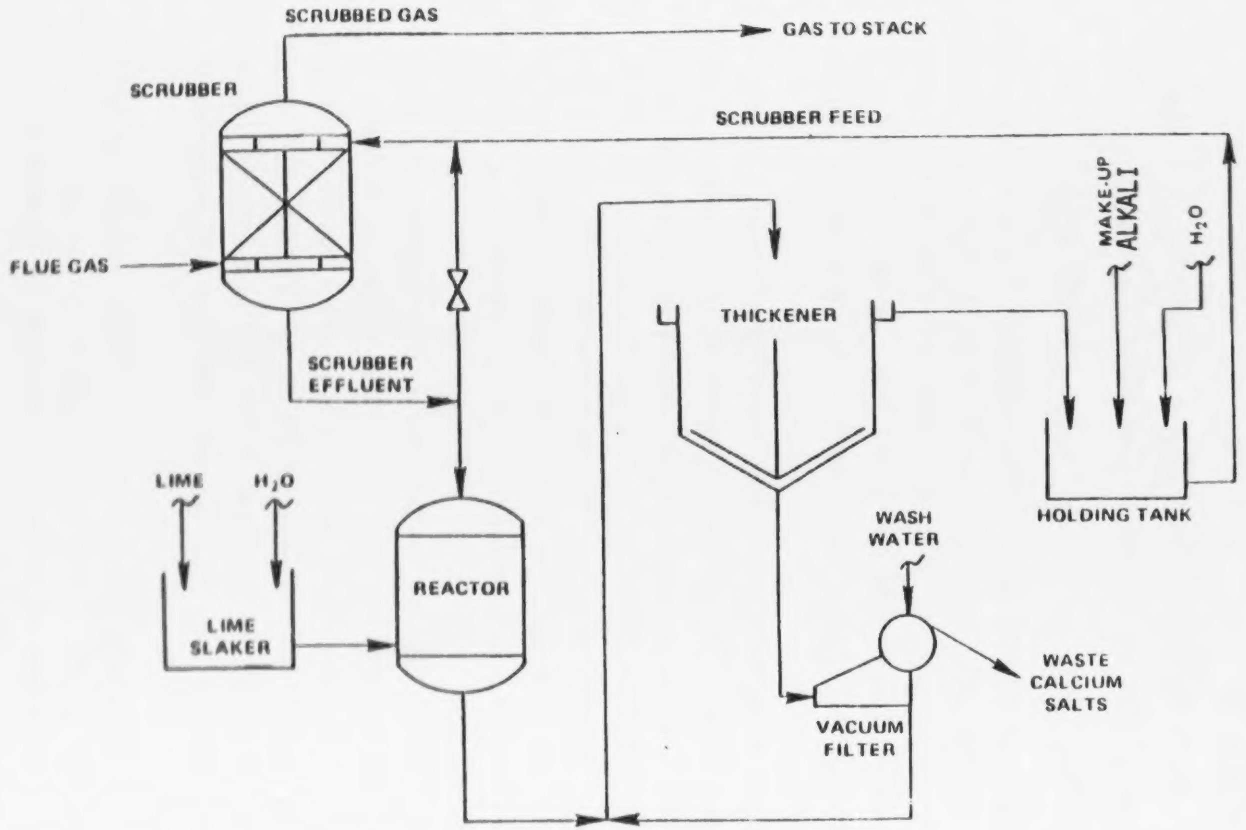
SCRUBBED GAS
GAS TO STACK
SCRUBBER
SCRUBBER FEED
FLUE GAS
MAKE-UP
ALKALI
H_2O
THICKENER
SCRUBBER
EFFLUENT
LIME
H_2O
HOLDING TANK
WASH
WATER
REACTOR
LIME
SLAKER
WASTE
CALCIUM
SALTS
VACUUM
FILTER

Figure 4.4. Simplified flow diagram for a sodium/lime double alkali process[46]

Table 4-6. SUMMARY OF OPERATING AND PLANNED INDUSTRIAL BOILER DOUBLE ALKALI SYSTEMS[48]

Installation/Location	Vendor or Developer	Size SCM/m	No. of FGD Units	Fuel Type[c]	Fuel % S	SO_2[a] Inlet (vppm)	SO_2[b] Outlet (vppm)	SO_2[a] Removal (%)	Waste Disposal
ARCO Polymers Monaca, PA	FMC	8,600	3	C	3	1,800	180	90	Landfill
Caterpillar Tractor Co. East Peoria, IL	FMC	5,900	4	C	3.2	2,000	200	90	Landfill
Caterpillar Tractor Co. Joliet, IL	ZURN	1,900	2	C	3.2	2,000	200	90	Landfill
Caterpillar Tractor Co. Mapleton, IL	FMC	6,700	5	C	3.2	2,000	200	90	Landfill
Caterpillar Tractor Co. Morton, IL	ZURN	1,100	2	C	3.2	2,000	200	90	Landfill
Caterpillar Tractor Co. Mossville, IL	ZURN	4,000	4	C	3.2	2,000	200	90	Landfill
Firestone Tire and Rubber Pottstown, NY	FMC	230	1	C	2.5-3.0	1,000	95	90.5	Landfill
General Motors Corp. Parma, OH	G.M.	3,600	1	C	2.5	800-1,300	80-130	90	Landfill
Grissom Air Force Base Bunker Hill, IN	Neptune/ Airpol	910	1	C	3.0-3.5	NA[d]	NA[d]	NA[d]	Landfill
Santa Fe Energy Corp. Bakersfield, CA	FMC	2,000	1	O	1.5	710	28	96	Landfill

[a] Inlet SO_2 and percent SO_2 removal are as reported to PEDCo by FGD system operators. Values reported may represent anything from single point wet chemical determinations to continuous monitoring results. Methods used to determine the values reported may or may not be EPA approved.

[b] Calculated.

[c] Coal - C
Oil - O

[d] Not available.

is treating a 230 Sm^3/min gas stream, and the largest application is treating a 8,600 Sm^3/min gas stream. No double alkali FGD systems have been installed on FCC unit regenerators.

4.2.4.4 System Performance. Double alkali FGD systems have achieved sulfur oxides removal efficiencies of at least 90 percent for flue gas streams from coal-fired boilers with inlet concentrations as high as 2,000 ppm and as low as 800 ppm. Design features and performance characteristics for operating dual alkali FGD systems are presented in Table 4-6.

4.2.5 Spray Drying FGD Systems[47]

4.2.5.1 Process Description. Spray drying FGD systems use an alkaline solution to absorb sulfur oxides from the flue gases. However, unlike the other types of FGD systems discussed, the L/G ratios for a spray drying FGD system are insufficient to saturate the gas stream with water. Consequently, the flue gas sulfur oxides react with the alkaline solution or slurry, dispersed in the gases as fine droplets. The droplets are quickly dried by the heat contained in the flue gases and become solid particles. The alkaline solution is prepared using soda ash or lime. Reaction between the alkaline solution and sulfur oxides proceeds both during and following the drying process. The mechanisms of the SO_2 removal reactions are not well understood. It has not been determined whether sulfur oxides removal occurs predominantly in the liquid phase, by absorption into the finely atomized droplets being dried, or by reaction between gas phase sulfur oxides and the slightly moist spray dried solids. The overall chemical reactions for this process are shown below.

$$SO_2 + Na_2CO_3 \longrightarrow Na_2SO_3 + CO_2$$

$$SO_2 + CaO + 1/2H_2O \longrightarrow CaSO_3 \bullet 1/2H_2O$$

In addition to these primary reactions, sulfate salts are produced by the following reactions:

$$Na_2SO_3 + 1/2O_2 \longrightarrow Na_2SO_4$$

$$SO_3 + Na_2CO_3 \longrightarrow Na_2SO_4 + CO_2$$

$$SO_2 + CaO + 1/2O_2 + 2H_2O \longrightarrow CaSO_4 \bullet 2H_2O$$

The resulting product is a dry mixture of sodium or calcium salts and unreacted sorbents which are collected using conventional particulate control equipment. Generally, particulate matter in the flue gases is not collected upstream of a spray drying FGD system. Thus, spray drying FGD systems provide both sulfur oxides and particulate emission control.

4.2.5.2 System Design. A generalized flow diagram for a spray drying FGD system is presented in Figure 4-5. Flue gases from the combustion device enter a spray dryer at temperatures generally between 130 to 160°C. The alkaline slurry is sprayed into the dryer as a finely atomized mist for contact with the hot flue gases. Gases exit the spray dryer and are routed to a conventional particulate collection device such as an electrostatic precipitator (ESP) or baghouse where spent reactant is removed for disposal. Systems using a baghouse for particulate removal report additional sulfur oxides sorption occurring in the baghouse. Care must be taken to maintain flue gas temperature well above saturation at this point to avoid condensation on the solids collection device surfaces.

Accessory equipment consists of reagent preparation and dry waste disposal facilities. In general, reagent preparation facilities include dry storage, a mix tank, and associated tanks and pumps. Facilities for handling the collected spray dryer waste product and transporting it to the ultimate disposal site are similar to those normally associated with baghouse or ESP collection devices.

4.2.5.3 Development Status. Spray drying FGD systems for removing sulfur oxides from boiler flue gases have been demonstrated by pilot-scale testing on industrial boiler sized systems (280 to 560 m^3/min) at several utility locations in the United States where low sulfur coals were being burned.[50] This technology is currently being offered commercially by several companies. Four spray drying FGD systems have been sold for industrial boiler applications and 10 for utility boiler applications. No spray drying FGD systems have been installed on FCC unit regenerators.

4.2.5.4 System Performance. Pilot plant studies have shown spray drying FGD can achieve sulfur oxides removal efficiencies up to 90 percent for low-sulfur utility and industrial coal-fired boiler

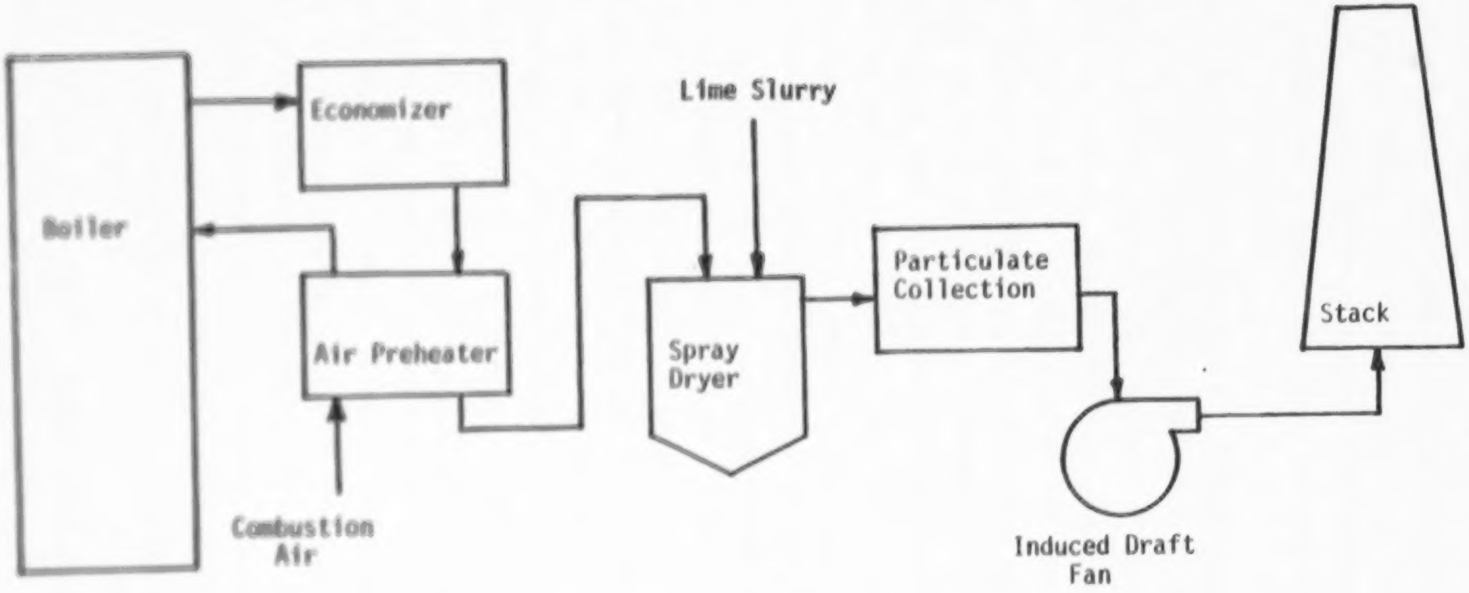
Boiler
Economizer
Air Preheater
Combustion Air
Lime Slurry
Spray Dryer
Particulate Collection
Induced Draft Fan
Stack

Figure 4-5. Simplified flow diagram for spray drying process[49]

applications. Removal efficiencies from 75 to 85 percent have been guaranteed by vendors for recent installations of spray drying FGD systems at industrial boiler sites (refer to Table 4-7).[51]

4.2.6 Wellman-Lord System[4,52,53]

4.2.6.1 Process Description. The Wellman-Lord system utilizes a regenerable sodium sulfite-bisulfite system to remove sulfur dioxide from the flue gas. The sodium sulfite scrubbing liquor reacts with sulfur dioxide in the flue gas to form sodium bisulfite and sodium sulfate. Thermal regeneration of the sodium sulfite produces a concentrated stream of sulfur dioxide. This sulfur dioxide can be further processed to elemental sulfur at the refinery sulfur plant.

The Wellman-Lord process consists of two basic stages, absorption and regeneration. The principal chemical reactions for these stages are:

Absorption

$$Na_2SO_3 + SO_2 + H_2O \longrightarrow 2NaHSO_3$$

$$Na_2CO_3 + SO_2 \longrightarrow Na_2SO_3 + CO_2$$

$$2Na_2SO_3 + O_2 \longrightarrow 2Na_2SO_4$$

$$2Na_2SO_3 + SO_3 + H_2O \longrightarrow 2NaHSO_3 + Na_2SO_4$$

Regeneration

$$2NaHSO_3 \longrightarrow Na_2SO_3 + H_2O + SO_2$$

4.2.6.2 System Design. A generalized flow diagram of the Wellman-Lord system is presented in Figure 4-6. Flue gas enters a variable throat venturi scrubber for particulate removal, cooling, and saturation of the flue gas. The flue gas then passes through a mist-eliminator. Within the absorber, the flue gas passes counter-currently through a tray-type absorber with sodium sulfite-bisulfite absorbing liquor. The scrubbed flue gas then passes through a mist-eliminator and is vented to the stack.

Spent scrubbing liquor is filtered to remove suspended solids and is heated in the evaporator to regenerate the scrubbing liquor. In the evaporator, the sulfur dioxide is stripped from the scrubbing

Table 4-7. SUMMARY OF SOME INDUSTRIAL BOILER SPRAY DRYING SYSTEMS[51]

Company and Location	Vendor	Sorbent	Size (scm/m)	Fuel		SO_2 Inlet (vppm)	SO_2 Outlet (vppm)	SO_2 Removal Efficiency[a] (%)
				Type	% Sulfur			
Strathmore Paper Co., Woronoco, MA	Mikropul	Lime	620	Coal	2-2.5	NA	NA	75
Celanese, Cumberland, MD	Wheelabrator-Frye/Rockwell International	Lime	1,400	Coal	1-2	800-2,500	NA	60-80

NA - Not available.

[a] Design.

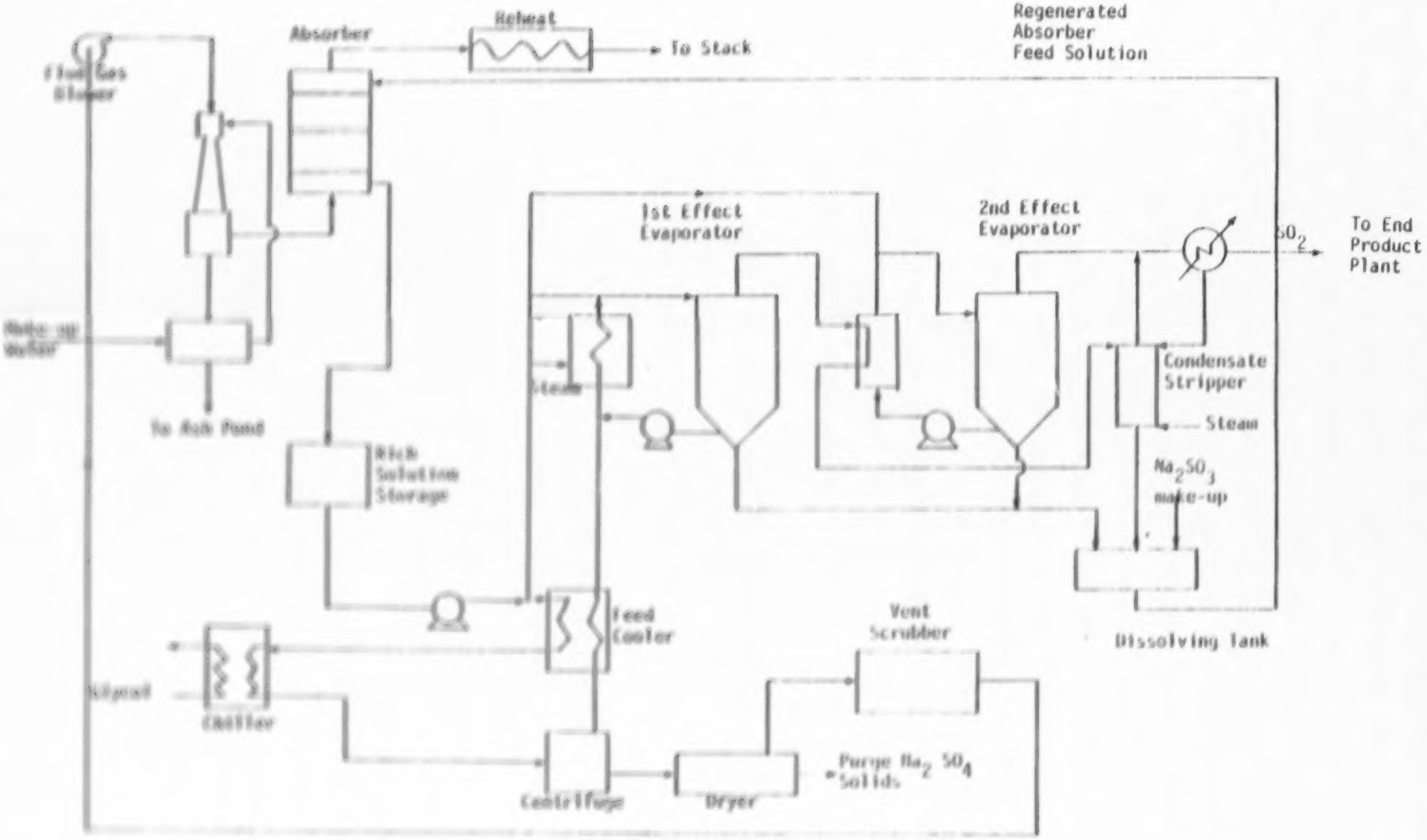
Flue Gas Blower
Make-up Water
To Ash Pond
Absorber
Reheat
To Stack
Regenerated
Absorber
Feed Solution
Rich Solution Storage
1st Effect Evaporator
Steam
2nd Effect Evaporator
SO_2
To End Product Plant
Condensate Stripper
Steam
Na_2SO_3 make-up
Dissolving Tank
Feed Cooler
Vent Scrubber
Glycol
Chiller
Centrifuge
Dryer
Purge Na_2SO_4 Solids

Figure 4-6. Process Flow Diagram Wellman-Lord Process[52]

liquor, regenerating the sodium sulfite. A purge stream removes small quantities of sodium sulfate, formed during absorption, and sodium thiosulfate, formed during regeneration, from the absorbing solution. This purge solution may contain 27 percent solids by weight. Soda ash is added to the scrubbing liquor to replenish sodium lost to purge. The scrubbing liquor is then returned to the absorber.

Vapors from the evaporator are cooled, condensed, and stripped of sulfur dioxide with steam. The vapors flow to a sulfur dioxide compressor system. From the compressor sulfur dioxide can be further processed in a Claus, liquid sulfur dioxide, or other end plant.

In general, reagent preparation facilities include soda ash storage and handling equipment.

4.2.6.3 Development Status. Wellman-Lord systems for removing sulfur oxides from flue gas have been installed on seven Claus sulfur plants, seven sulfuric acid plants, three industrial boilers, and four utility boilers.[4]

4.2.6.4 System Performance. Actual performance achieved by Wellman-Lord systems is 90 percent or greater removal of sulfur dioxide. A summary of operating Wellman-Lord systems in the U.S. is presented in Table 4-8.

4.2.7. Citrate-Based FGD Systems[55,56,57,58,59,60]

4.2.7.1 Process Description. Two citrate processes are currently available, the Bureau of Mines process and the Flakt-Boliden process. A third, the Peabody process, has been used in one pilot plant study and represents a specific application of the Bureau of Mines process with modification.

The Bureau of Mines and Flakt-Boliden citrate processes are essentially the same in terms of SO_2 removal. Both processes use a citric acid buffered solution to absorb SO_2 from the flue gases. The basic reactions which occur during absorption are:

$$SO_2 + H_2O \longrightarrow HSO_3^- + H^+$$
$$H^+ + Cit^{\equiv} \longrightarrow HCit^=$$
$$H^+ + Cit^= \longrightarrow H_2Cit^-$$
$$H^+ + Cit^- \longrightarrow H_3Cit$$

Where: Cit = citrate ion

Table 4-8. SUMMARY OF OPERATING WELLMAN-LORD SYSTEMS IN THE U.S.[54]

Company/Location	Completion Date	Feed Gas Origin	Gas Flow 1000 Nm^3/hr	Gas Flow (scfm)	Design SO_2 Concentration ppm	Disposition of SO_2
Olin Chemical* Paulsboro, New Jersey	July 1970	Sulfuric Acid Plant	76	(45,000)	in 6,000 out 500	Recycle to acid plant
Std. Oil of California El Segundo, California	September 1972	Claus Plants	51	(30,200)	in 10,000 out 250	Recycle to Claus plant
Allied Chemical Calumet, Illinois	November 1972	Sulfuric Acid plants	51	(29,850)	in 2,700 out 250	Recycle to acid plants
Olin Chemical Curtis Bay, Maryland	May 1973	Sulfuric Acid plants	133	(78,046)	in 4,000 out 250	Recycle to acid plants
Std. Oil of California Richmond, California	August 1974	Claus plant	51	(30,000)	in 10,000 out 250	Recycle to Claus plant
Std. Oil of California El Segundo, California	January 1975	Claus plant	51	(30,000)	in 10,000 out 250	Recycle to Claus plant
Northern Indiana Public Service Gary, Indiana	December 1976**	Coal-fired boiler (115 MW)	527	(310,000)	in 2,200 out 200	Elemental sulfur
Public Service Co. of New Mexico Waterflow, New Mexico	November 1978	Coal-fired boiler (316 MW)	--	--	90% removal	Elemental sulfur
Public Service Co. of New Mexico Waterflow, New Mexico	November 1978	Coal-fired boiler (306 MW)	--	--	90% removal	Elemental sulfur

*Plant operation suspended as of January 1, 1976.

**First integrated operation of the plant was in December 1976; however, the Wellman-Lord system began operations in July 1976, before completion of the Allied sulfur recovery unit.

The first equation accounts for over 90 percent of the SO_2 removal from the flue gases.[61] The three citrate disassociation equilibria provide buffering to keep the pH in the optimum range for absorption (4 to 5 for the Bureau of Mines process,[60] 3 to 5 for the Flakt-Boliden process.[62] For specific applications, the exact pH needed (determined by the SO_2 concentration in the feed) is maintained by adding sodium hydroxide or soda ash to form the sodium citrate absorbent solution.

During the absorption process, some of the SO_2, approximately 1.5 percent of the amount absorbed for the Bureau of Mines process[63] and less than 1 percent for the Flakt-Boliden process,[64] is oxidized, forming sulfate ions and, thus, sulfuric acid by the following reaction:

$$HSO_3^- + H^+ + 1/2O_2 \longrightarrow H_2SO_4$$

In addition, the SO_3 that is not removed in the gas scrubbing system forms sulfuric acid in the citrate solution. The sulfuric acid is neutralized through the addition of caustic (NaOH), or soda ash, by the following reaction:

$$H_2SO_4 + 2NaOH \longrightarrow Na_2SO_4 + 2H_2O$$

The resulting sodium sulfate decahydrate is continuously removed from the citrate solution by vacuum crystallization. The crystallized sulfate, Glauber's salt, may then be disposed of as a waste or sold for use as a secondary feedstock in the chemical industry.

4.2.7.2 System Design. Both the Bureau of Mines and the Flakt-Boliden system can be considered in terms of the following steps:

- Flue gas pretreatment
- SO_2 absorption
- Absorbent regeneration
- Sulfur product recovery
- Purge treatment

A generalized flow diagram for the Bureau of Mines system and the Flakt-Boliden system are shown in Figures 4-7 and 4-8, respectively.

Flue Gas Pretreatment. In both systems, the offgases are cleaned prior to entering the absorber. Offgases may be cleaned first by a variety of high efficiency particulate collectors and then by electrostatic mist precipitators (wet ESP) or venturi scrubbers. This flue gas precleaning is designed to remove particulates, chlorides, and sulfuric acid mist. A waste stream from the scrubber is generated and needs to

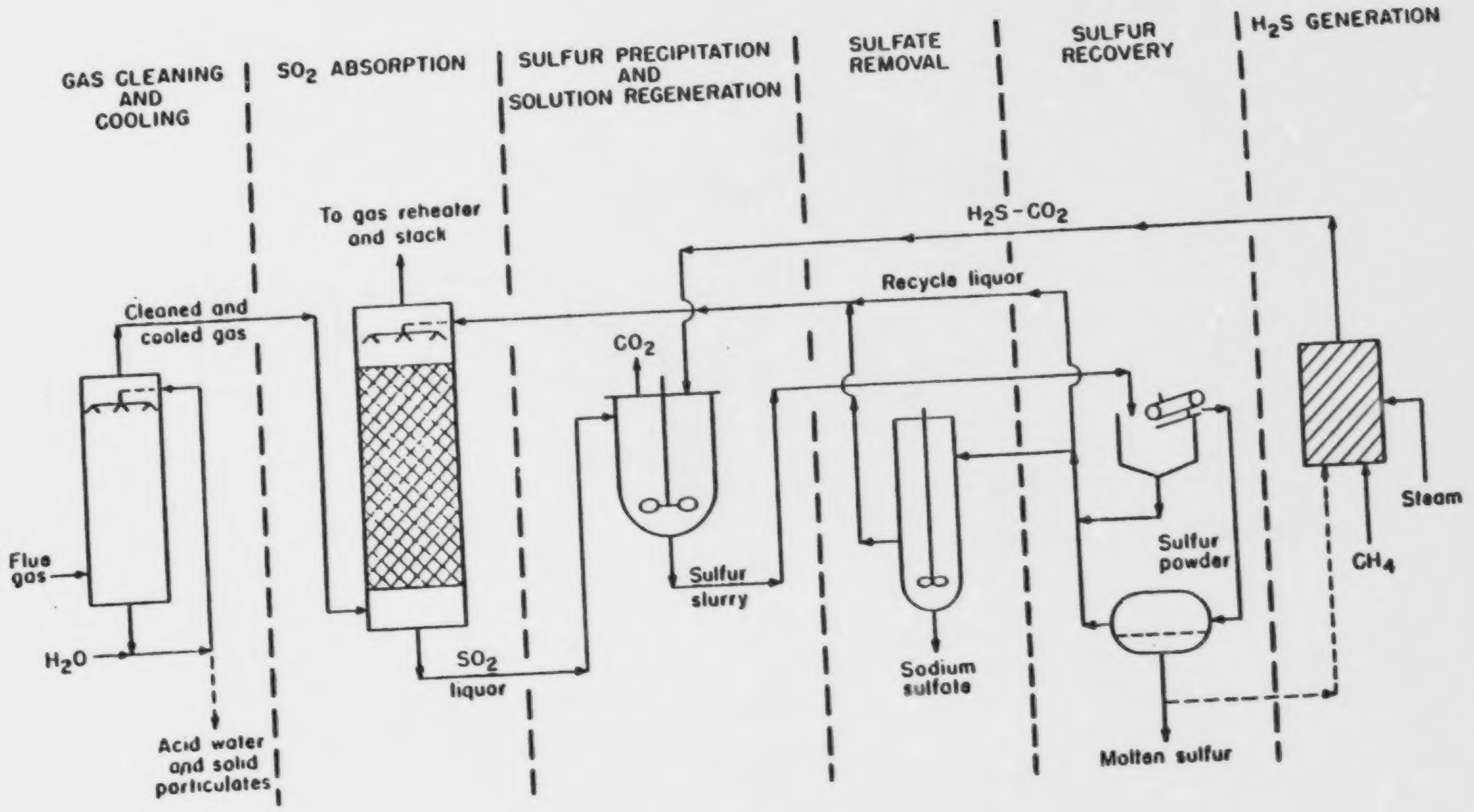
GAS CLEANING AND COOLING
SO2 ABSORPTION
SULFUR PRECIPITATION AND SOLUTION REGENERATION
SULFATE REMOVAL
SULFUR RECOVERY
H2S GENERATION
Flue gas
H2O
Cleaned and cooled gas
Acid water and solid particulates
To gas reheater and stack
SO2 liquor
CO2
Sulfur slurry
H2S - CO2
Recycle liquor
Sodium sulfate
Sulfur powder
Molten sulfur
Steam
CH4

Figure 4-7. Flow Diagram for the Bureau of Mines Citrate Process

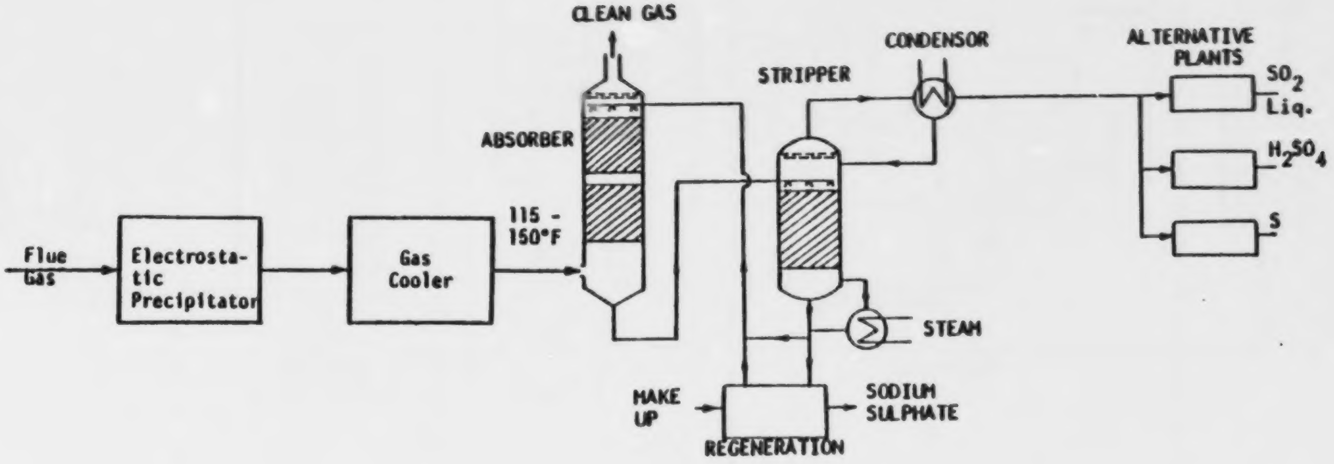
Flue Gas
Electrostatic Precipitator
Gas Cooler
115 - 150°F
CLEAN GAS
ABSORBER
STRIPPER
CONDENSOR
STEAM
MAKE UP
REGENERATION
SODIUM SULPHATE
ALTERNATIVE PLANTS
SO2 Liq.
H2SO4
S

Figure 4-8. Flow Diagram for the Flakt-Boliden Citrate Process

be disposed of in an environmentally acceptable manner. Removal of acid mist helps to minimize sodium sulfate formation in the absorber. Sodium sulfate formation would increase the purge requirements. Offgases are typically cooled to 46 to 66°C during pretreatment.[65]

SO_2 Absorption. In both systems, the cooled, saturated gases enter the bottom of a packed-column absorption tower where they flow countercurrent to the absorbent (i.e., the sodium-citrate buffered solution). The absorption process is pH dependent. As SO_2 enters the absorbent solution, the pH decreases. The citrate acts as a buffer, maintaining the pH in the desired range for absorption. Absorption takes place at atmospheric pressure between 38 and 54°C.[66] The cleaned gases are released to the atmosphere, after passing through a demister.[67]

Absorbent Regeneration. The two systems differ in both the absorbent regeneration and the sulfur product recovery steps. In the Bureau of Mines system, the absorbent, now loaded with SO_2, is sent to a closed reactor that is agitated and operates at 52 to 54°C and about 206 kPa.[68] In the reactor, the SO_2-laden absorbent is reacted with hydrogen sulfide (H_2S). The following reaction takes place:

$$HSO_3^- + H^+ + 2H_2S \longrightarrow 3S + 3H_2O$$

This reaction regenerates the absorbent and produces a slurry of elemental sulfur and regenerated absorbent. Unreacted H_2S is combined with the offgases prior to entering a catalytic (or thermal) incinerator. Within the incinerator, the H_2S is oxidized to SO_2. The combined gas stream then enters the offgas pretreatment system.[69]

In the Flakt-Boliden system, the SO_2-laden absorbent is pumped from the bottom of the absorption tower to the top of a stripping tower. The stripping, which may take place at atmospheric pressure or under vacuum,[70] is accomplished by steam treatment in countercurrent flow to the SO_2-laden absorbent. The steam accepts the SO_2 from the citrate solution, reversing the chemical reactions given in Section 4.2.4.1. This stripping process thus regenerates the absorbent and produces a mixture of SO_2 and water that exits the stripper at the top.

Sulfur Product Recovery. In the Bureau of Mines system, the elemental sulfur-regenerated absorbent slurry leaves the reactor. The elemental sulfur is separated from the absorbent by either oil or air flotation.

The flotation process results in two separate streams; one is a concentrated sulfur slurry, the other, the absorbent. The concentrated sulfur slurry is treated to remove the sulfur from the slurry by melting the regenerated sulfur and decanting the remaining absorbent. The molten sulfur drawn off is a high-quality molten yellow sulfur.

In the Flakt-Boliden system, the mixture of SO_2 and water leaving the stripping tower is cooled in a condenser where most of the water is separated. The condensate, containing only a small amount of SO_2, is returned to the stripping tower. The concentrated SO_2 gas can be conveyed directly to a Claus plant for the production of elemental sulfur, to a contact plant for sulfuric acid production, or to a refrigeration unit for condensation to liquid SO_2.

Purge Treatment. In both systems, the absorbent reclaimed during the absorbent regeneration step contains small amounts of sodium sulfate. Before the absorbent is recycled to the absorption tower, a small stream is sent to a crystallizer where the sodium citrate and sodium sulfate are selectively crystallized. The sulfate is removed as Glauber's salt by cooling the solution to a temperature well above the freezing point of water.

4.2.7.3 Developmental Status. The Bureau of Mines citrate process was devised in 1968 for application in the nonferrous smelting industry. A pilot plant was constructed and operated in 1970 at the Magma Copper Company's San Manuel smelter in Arizona. Another pilot plant was constructed at the Bunker Hill base metal smelter in Kellogg, Idaho, in 1976. The first commercial unit was completed in 1979 at a powerplant owned and operated by St. Joe Minerals Co. The Flakt-Boliden process is based on work begun in the early 1970s by the Boliden Company of Sweden, the Norwegian Technical Institute Sintef, and Flakt (Svenska Flaktfabriken). A pilot plant using the Flakt-Boliden process has been used at the Boliden works in Sweden, treating copper and lead smelter flue gases. The Electric Power Research Institute is sponsoring a pilot plant at TVA's Colbert Steam Plant in Alabama. Although neither process has been applied to any FCC unit regenerator, one is currently under construction to control SO_2 emissions from the FCC unit regenerator at the Saber refinery in Corpus Christi, Texas. Table 4-9 summarizes the application of citrate process systems.

Table 4-9. CITRATE FGD PROCESS UNITS[a]

Location	Feed gas origin	Gas volume treated Nm³/m	SO_2 concentration, vppm	SO_2 Removal, %	Disposition of SO_2
Magma Copper Co. San Manuel, Arizona (Bureau of Mines)	Copper smelter	8.5	10,000-15,000	93-99	Elemental sulfur
Bunker Hill Kellogg, Idaho (Bureau of Mines) 4500 hours operation	Lead smelter	28	3,000-10,000 (typically 5,000)	>90	Elemental sulfur
Pfizer Terre Haute, Indiana	Coal-fired boiler	57	1,000-2,000	95-97	Elemental sulfur
Boliden Aktiebolag Skelleftehamn, Sweden (Flakt) Operational since Sept. 1976	Copper, lead, and zinc smelters	83	5,000-50,000 (typically 30,000)	90-99	Liquid SO_2
St. Joe Minerals Monaca, Pennsylvania (Bureau of Mines) Early 1980 startup scheduled for this 60-MW power boiler FGD system	Coal-fired power boiler	4,420	2,000	>90 (design)	Elemental sulfur
Tennessee Valley Authority Tuscumbia, Alabama (Flakt) Startup planned for early 1980	Coal-fired power boiler	83	2,000-4,000 (typically, 2,400)	90	
Site to be selected (Flakt) Site selection expected in mid-1979	100-MW coal-fired power boiler				
Saber Refining Company Corpus Christi, Texas Startup planned for 1983	FCC unit regenerator				

[a] Reference 56.

4.2.7.4 System Performance. The pilot plant studies of the Bureau of Mines process have shown SO_2 removal efficiencies over 90 percent and up to 99 percent. It has been stated that sulfur recovery efficiencies can be in excess of 99 percent for refinery applications.[71]

The Flakt-Boliden process is also capable of removing over 90 percent of the SO_2 from the flue gas.[72] A summary of the design characteristics of previous, operating, and planned citrate process systems is found in Table 4-9.

4.3 FEED HYDROTREATING

Hydrotreating is a refinery process used to pretreat catalytic cracking feeds and other process feeds by removing metal, nitrogen, and sulfur compounds. Hydrotreating is also used to stabilize and to improve the quality of finished products (e.g. kerosine, fuel oils, lubrication oils) prior to being sold. The decision by a refiner to install a hydrotreating unit is based primarily on process and economic considerations. Feeds are hydrotreated to remove sulfur to lower the sulfur content of refinery products; to remove metals, nitrogen, sulfur compounds to prevent poisoning of catalysts used in refinery processes and, consequently, achieve longer runs, better cracking selectivity, and improved product yield; and to remove corrosive compounds to prolong the operating life of refinery process equipment.[73]

The hydrotreating of feedstocks prior to processing by catalytic cracking removes sulfur compounds from the FCC feed. The amount of sulfur contained in coke deposits on the cracking catalysts and ultimately converted to sulfur oxides in the FCC regenerator is determined by the characteristics of sulfur compounds in the FCC feed. In general, processing a high sulfur FCC feed results in higher FCC regenerator sulfur oxides emissions than processing a low sulfur FCC feed. Therefore, feed hydrotreating will contribute to lowering FCC regenerator sulfur oxides emissions to the atmosphere.

4.3.1 Process Description

Many commercial hydrotreating processes are available.[74] Although variations exist between these processes the basic operations are similar. A generalized diagram of the hydrotreating process is shown in Figure 4-9.

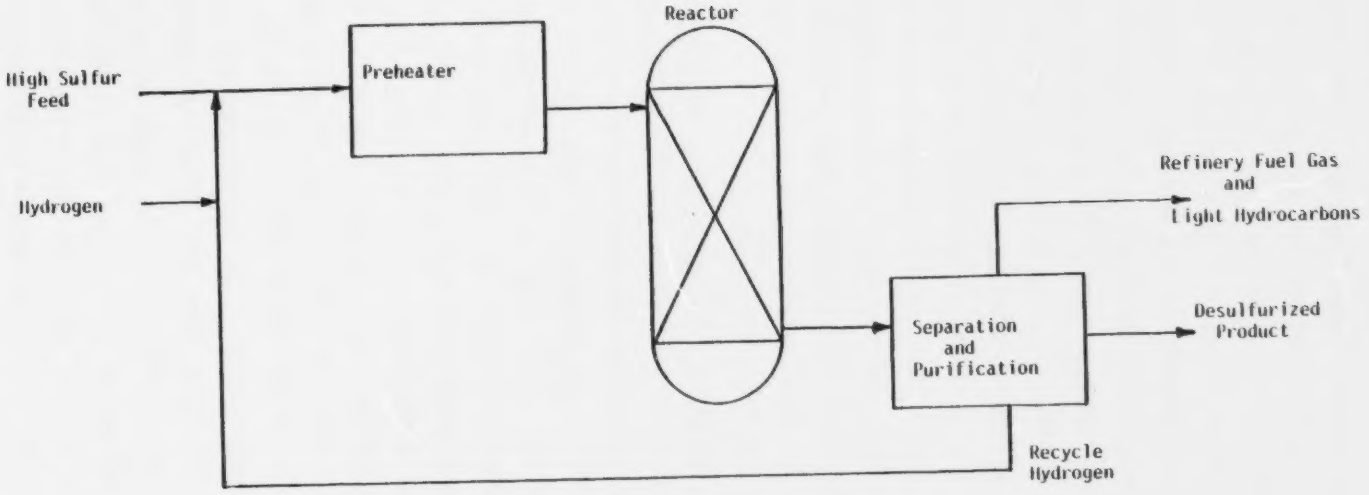
Reactor
High Sulfur Feed
Preheater
Hydrogen
Refinery Fuel Gas and Light Hydrocarbons
Desulfurized Product
Separation and Purification
Recycle Hydrogen

Figure 4-9. General process schematic for feed hydrotreating

The FCC feedstock to be treated is combined with hydrogen gas and preheated to about 370°C at high pressures. This combined feedstream enters a reactor containing catalysts which initiate reactions between the hydrogen and the hydrocarbon molecules. Depending on how sulfur is bound to the hydrocarbon molecules, sulfur in the hydrocarbon molecules can be replaced by hydrogen to form primarily saturated hydrocarbons, hydrogen sulfide, and other gases.[75] Hydrogen also reacts with nitrogen compounds in the feedstock to form ammonia. There is a net consumption of hydrogen during this process.

Effluent from the reactor vessel is cooled and separated into its liquid and gaseous components. The gaseous fraction contains mostly unreacted hydrogen, hydrogen sulfide, and ammonia. Both the hydrogen sulfide and ammonia are scrubbed from the light hydrocarbon stream and are disposed or recovered separately. The unreacted hydrogen is recovered and returned to the reactor. The desulfurized liquid fraction is separated into light and heavy hydrocarbon products that are used as feedstocks for fluid catalytic cracking units and other refinery processes or are sold as finished products.[74,75]

4.3.2 Potential for Reducing FCC Regenerator Sulfur Oxides Emissions

Reductions in sulfur oxides emissions from FCC regenerators are related to the amount of sulfur removed from the FCC feedstock. Hydrotreating units (HDT) are capable of reducing FCC feedstock sulfur levels to over 98 percent.[74-78] Coke sulfur and regenerator sulfur oxides emissions, however, are not reduced by equivalent amounts. Pilot plant studies and commercial operations have shown that when various FCC feedstocks containing 1.7 to 2.8 weight percent sulfur are desulfurized 88 to 96 percent and charged to an FCC unit, coke sulfur and sulfur oxides emissions are only reduced 62 to 94 percent.[79,80]

This difference in sulfur reductions is attributable to variations in the feedstock characteristics. FCC feedstocks are a combination of straight chain, ring, multiple ring, and other hydrocarbon molecules. The sulfur present in the feedstock may be bound in relatively simple molecules such as mercaptans or in complex ring molecules called thiophenes. Feedstocks which have relatively high proportions of polyaromatic compounds and thiophenes are more difficult to hydrotreat than those feedstocks that contain simple sulfur compounds. More hydrogen and higher desulfurization severity (higher temperature and pressure) are required to achieve high reductions of sulfur from aromatic and thiophenic feeds.[76,79,81,82]

When hydrotreated feeds are charged to the FCC unit, the remaining feed sulfur distributes between the products and the coke. If the HDT feedstock contains primarily simple sulfur compounds, reductions in coke sulfur and regenerator sulfur oxides emissions may approximate the reductions in FCC feed sulfur content. If the HDT feedstock contains high proportions of polyaromatics and thiophenes, however, reductions in coke sulfur and sulfur oxides emissions may be considerably lower than the FCC feed sulfur reductions. The sulfur-containing molecules which remain in hydrotreated aromatic feedstocks preferentially form coke. These hydrotreated feedstocks thus yield higher coke sulfur and sulfur oxides emissions than other hydrotreated feedstocks with identical sulfur contents.[76,79,81,82] Performance data for hydrotreating of FCC feedstocks is presented in Table 4-10.

4.3.3 Additional Benefits Derived From FCC Feed Hydrotreating

There are many properties of high sulfur FCC feeds which make these potential feedstocks undesirable. Feeds which contain sulfur in non-thiophenic forms give high hydrogen sulfide yields and high sulfur gasoline when charged to an FCC unit. Sulfur in thiophenic compounds yields high sulfur cycle oils and high sulfur in coke.[87] High molecular weight ring compounds in aromatic feeds preferentially adsorb on the FCC catalyst and form coke. The high nitrogen and metals contents either poison the FCC catalyst or increase the yields of undesirable products such as coke and gas.[87]

Hydrotreating of potential FCC feedstocks, including gas oils, deasphalted oils, atmospheric tower bottoms, and various residual feeds, improves the feed cracking characteristics and reduces feed sulfur, nitrogen, and metals contents. Desulfurized FCC feedstocks exhibit improved yields of gasoline blending stocks, lower product sulfur levels, and reduced coke and gas yields over untreated feedstocks.[5,81,82,89] A gasoline yield improvement of up to 20 percent for desulfurized over untreated FCC feedstocks has been observed.[90] Also, FCC throughput may, in some cases, be increased due to higher first pass conversion of the feed into useful products.[5] These yield

Table 4-10. PERFORMANCE DATA FOR HYDROTREATING OF FCC FEEDSTOCKS

Crude Oil Source	HDT Feedstock	Sulfur Content (wt.%)		Sulfur Reduction (%)	FCC Regenerator SO_x Emissions (vppm dry)	HDT Unit Type[b]	Ref.
		HDT Feed	HDT Product				
NR[a]	Heavy Gas Oil	1.76	0.24	86	NR	C	83
NR	Heavy Gas Oil	2.20	0.2	90	NR	C	84
West Texas	Atm. Residua	2.2	0.33	85	660	C	78
Light Arabian	Atm. Residua	2.93	0.12	96	330	C	78
Kuwait	Atm. Residua	3.8	0.28	92	660	C	78
Kuwait	Atm. Residua	3.8	0.10	97	210	C	78
South Louisiana	Atm. Residua	0.46	0.05	87	NR	C	78
West Texas	Gas Oil	1.75	0.21	88	470	P	80
West Texas	Gas Oil	2.59	0.24	91	374-500	P	85
Kuwait	Gas Oil	2.66	0.11	96	236	P	80
Alaskan	Atm. Residua	1.59	0.3	81	520	P	86

[a] NR = Not reported.

[b] C = Commercial HDT unit P = Pilot plant HDT unit.

and product quality shifts result from the hydrogenation and saturation of organic sulfur and polyaromatic compounds in the feed. The magnitude of the yield and quality shifts depends on the quality of the untreated feedstock and the degree of hydrotreating.

The hydrotreating of FCC feedstocks may also result in air quality benefits beyond the reduction in FCC regenerator sulfur oxides emissions. Because there are no government or industry-wide sulfur content specifications for gasoline, catalytic cracked gasoline is normally not hydrotreated prior to blending with other gasoline stocks. However, by removing sulfur compounds, hydrotreating of FCC feedstocks reduces the sulfur content of gasoline obtained by catalytic cracking. Lower sulfur contents in gasoline result in reduced sulfur oxides emissions to atmosphere from the combustion of gasoline in motor vehicle engines.[114]

4.3.4 Development Status

As of January 1979, 31 refineries were pretreating all or a portion of their FCC charge stock. The total U.S. FCC feed hydrotreating capacity was 142,000 m^3/sd or about 18 percent of the total FCC fresh feed capacity. It is expected that this percentage will increase as refiners increase their ability to process high sulfur crudes.[91]

Economic and process considerations affect the decision by a refiner to install an FCC feed hydrotreating unit. It is unlikely that an FCC feed hydrotreater would be installed solely to comply with regenerator sulfur oxides limitation. The investment required by a refiner to install a hydrotreating unit varies with the type of hydrotreating process selected and the types of feedstocks to be treated. Typical capital costs for hydrotreating units range from \$2,000 to \$10,000 per cubic meter of feed per stream day (m^3/sd).[92] In general, the costs for hydrotreating gas oils are at the lower end of the range and the costs for hydrotreating residuum are at the upper end of the range. For example, the capital cost for a 2,500 m^3/sd hydrotreating unit processing Middle East vacuum gas oil at 90 percent desulfurization is approximately \$8 million.[84] The capital cost for an 8,000 m^3/sd hydrotreating unit processing Arabian Heavy residuum at 98 percent desulfurization is approximately \$80 million.[93] Because a net consumption of hydrogen occurs during hydrotreating, hydrogen costs can be significant. In most refineries, sufficient hydrogen to handle normal hydrotreating requirements is available as a byproduct from catalytic reforming.[73] However, if separate hydrogen manufacturing facilities are needed, the capital costs for a new hydrotreating unit at a specific refinery will be higher than the costs estimated for the example hydrotreating units.

A major process consideration influencing a refiner's decision to install a hydrotreating unit is the need to protect catalysts susceptible to poisoning by sulfur, nitrogen, and metal compounds in process feedstocks. Without hydrotreating the feedstock, catalyst life is greatly reduced. Therefore, the cost of hydrotreating is justified by longer catalyst life, better product yields, and better product quality. Other process considerations include a refiner's desire to protect refinery equipment from corrosive compounds and to meet finished product specifications.

4.4 PROCESS CHANGES

Since sulfur oxides emissions from the FCC regenerator are determined, for any given feedstock, by the amount of coke formed on the FCC catalyst, process adjustments which decrease coke production may also reduce sulfur oxides emissions. Three technological developments have given FCC operators considerable flexibility in controlling product yields, operating conditions, and sulfur oxides emissions. These are:[94]

(1) Zeolite catalysts

(2) Transfer line (riser) cracking

(3) High temperature or carbon monoxide-promoted regeneration.

Other process changes, such as adjustments in the type and quantity of feed recycle, may also be used to reduce regeneration sulfur oxides emissions.

4.4.1 Zeolite Catalysts

Catalyst evolution has resulted in high activity zeolite catalysts which have higher cracking activity, greater liquid yields and improved stability over early amorphous catalysts.[95,96] High activity zeolite catalysts can reduce the production of coke on FCC catalysts when compared to older catalysts. Aromatic compounds preferentially form coke on the FCC catalyst and increase sulfur oxides emissions; because of their high activity, zeolite catalysts can promote the dehydrogenation of feed aromatic compounds and, therefore, reduce sulfur oxides emissions.

The amount of time the catalyst is in contact with the FCC hydrocarbon feed and other factors such as feed temperature may result in greater coke formation.[95] Refiners may periodically adjust the contact time to maximize the yields of certain products.[97] To control sulfur oxides emissions from the regenerator, a refiner may choose to minimize catalyst/hydrocarbon contact times and coke production.

4.4.2 Transfer Line (Riser) Cracking

The development of zeolite catalysts spurred the development of transfer line or riser cracking. Transfer line cracking refers to the action of cracking the FCC hydrocarbon feed partially or entirely within the pipe that transfers the regenerated catalyst and feed hydrocarbons to the separator vessel. In early FCC units, most hydrocarbon cracking occurred on a fluidized bed of catalyst, hydrocarbons, and steam inside what is now called the separator vessel.

Short contact time riser cracking techniques result in optimal utilization of high activity zeolite catalysts. Zeolite catalysts in conjunction with riser cracking enable the refiner to reduce coke formation.[98] In part, the degree of control is dependent on the characteristics of the FCC hydrocarbon feed.

4.4.3 New Regeneration Techniques

Variables associated with regeneration have an impact on regenerator emissions. The efficiency of coke burn-off during the regeneration process directly affects the production of coke during the hydrocarbon cracking reactions, and thus affects emissions from the regenerator. Regeneration efficiency is measured by determining the weight percent of carbon that remains on the regenerated catalyst (CRC). Since large coke deposits (high CRC) inhibit zeolite catalyst activity, it is usually desirable to minimize CRC by efficiently burning off the coke deposits.[99]

New techniques have been developed to simultaneously increase regeneration efficiency and reduce the emissions of carbon monoxide from the FCC regenerator. High temperature regeneration uses higher temperatures than conventional regeneration to burnoff catalyst coke deposits. Carbon monoxide oxidation-promoted regeneration uses catalysts to promote the complete combustion of carbon monoxide.

Conventional regeneration techniques presently used by most refiners yield CRC on the order of 0.1 to 0.6 weight percent.[7,100,101] The latest regeneration techniques can reduce CRC to about 0.02 weight percent.

It is difficult to separate emissions effects which result from process changes involving catalysts, riser cracking, or complete regeneration techniques. It has been estimated that the combined effect of these process changes has been a 40 percent reduction in sulfur oxides emissions from units which have used the processes.[94] Process changes which involve catalysts, riser cracking variables, and regenerator conditions may alter coke production from over 6 percent to 4 percent by weight of the FCC feed for commonly used feedstocks.[102] Such a change would be expected to yield greater than 33 percent reductions in regenerator sulfur oxides emissions for a given feedstock if coke sulfur remains constant.

4.4.4 Other Process Changes

Other process changes which affect regenerator sulfur oxides emissions involve changes in the coke make rate. Often, small portions of the heavy FCC products are recycled from the fractionator for additional cracking to increase the yields of certain products. Maximum gasoline yield is obtained, for example, by recycling a portion of the distillate product material.[103] This action, however, increases coke production and mass emissions of sulfur oxides. It has been estimated that a 5 volume percent decrease in heavy oil recycle would result in a decrease in coke production of 0.3 weight percent.[104] An increase in conversion increases gasoline production. This action, however, also increases coke production and mass emissions of sulfur oxides.

4.5 SULFUR OXIDES REDUCTION CATALYSTS

An emerging technology for the control of FCC regenerator sulfur oxides emissions uses special catalysts which influence the movement of sulfur within the FCC unit. Sulfur oxides formed during catalyst regeneration are captured on these special catalysts, thus preventing emissions to the atmosphere. In the FCC reactor and separator vessel, the captured sulfur oxides are transformed into hydrogen sulfide and vented with the cracked hydrocarbon vapors to the fractionator and ultimately to the refinery sulfur plant. Reductions as high as 90 percent have been achieved in small scale bench and pilot plant tests, while up to 80 percent reduction has been obtained in commercial tests.[82,105-108] About 8 percent of nationwide FCC unit processing capacity utilize first generation sulfur oxides reduction catalysts. These catalysts have limited sulfur oxide reduction capabilities and typically achieve 30 to 40 percent sulfur oxide emissions reduction over normal catalysts.[111]

4.5.1 Process Description

Although several oil companies and catalyst vendors are developing the sulfur reduction catalyst sulfur oxides control technique, the reaction mechanisms involved are similar[82,109] and are summarized below:

Regenerator Reactions:

$S \text{ (in coke)} + O_2 \longrightarrow SO_2$	Sulfur Burning
$SO_2 + 1/2\ O_2 \longrightarrow SO_3$	SO_2 Oxidation
$SO_3 + \text{metal (in catalyst)} \longrightarrow MSO_4$	Metal Sulfate Formation

Reactor/Separator Reactions:

$MSO_4 + 4H_2 \longrightarrow MS + 4H_2O$	Metal Sulfate Reduction
$MS + H_2O \longrightarrow MO + H_2S$	Sulfide Hydrolysis

Sulfur in the catalyst coke is oxidized to sulfur dioxide and sulfur trioxide in the FCC regenerator. The sulfur trioxides combine with metals (usually aluminum or magnesium) in the special catalyst to form metal sulfates which are stable under internal regenerator conditions. The regenerated catalyst and the metal sulfates are then routed to the reactor as in normal FCC operations.

Interpretations of the reaction mechanisms which convert the metal sulfates to hydrogen sulfide in the reactor/separator vary slightly. Amoco suggests that the metal sulfates are reduced in the presence of the hydrocarbon feed and that the metal sulfides are hydrolyzed in the steam stripper section of the separator vessel.[79] Patents issued to Chevron indicate that the steam stripper may not be involved in the sulfide hydrolysis.[100] In either case, the hydrogen sulfide thus formed is vented to the FCC fractionator with the product stream. The hydrogen sulfide is eventually separated from the liquid products and processed into elemental sulfur at the refinery sulfur recovery plant. The catalyst is returned to the regenerator vessel to burn off coke deposits and to begin the sulfur oxides capture process. As with conventional fluid catalytic cracking, the process is continuous.

The sulfur active catalysts may be present in several forms in the catalyst inventory. It may either be incorporated into the cracking catalyst or added as a separate solid which would constitute a portion of the total FCC catalyst inventory.

4.5.2 Development Status

Sulfur oxides reduction catalysts have been under development for several years. Many bench scale and pilot plant tests have been conducted, and a limited number of commercial tests have been performed. Results of bench scale, pilot plant, and commercial tests show that sulfur oxides emissions reductions are high as 90 percent have been achieved with development sulfur oxides reduction catalysts.[112] Several problems have been encountered by some of the process developers in obtaining pilot plant results in commercial operations. Nevertheless, a recent commercial scale test of a commercially available sulfur oxides reduction catalyst, summarized in Appendix C, and other commercial scale tests of developmental sulfur oxides reduction catalysts, summarized in Table 4-11, show that sulfur oxides reduction catalysts are capable of reducing the regenerator emissions from an FCC unit processing a 1 percent sulfur feed by about 80 percent.[106,108,112] Based on these commercial test data, sulfur oxides reduction catalysts are expected to achieve 80 percent reduction in sulfur oxides emissions from FCC units processing 1 to 2 percent sulfur feeds when developed.

Table 4-11. Summary of SO_x REDUCTION CATALYST PERFORMANCE DATA[112]

Company	FCC Unit Regeneration Mode	Feed Sulfur Level (Weight Percent)	Estimated SO_x Emission Reduction[a,b] (Percent)	Controlled SO_x Emission Level (kg/1,000 kg coke burn-off)
ARCO	Conventional	1.10	73	8.5[c,d]
ARCO	HTR with CO Promoter	1.18	57	14.7[d]
ARCO	HTR with CO Promoter	0.31	30	7.7[d]
Chevron	Conventional with CO Promoter	0.99	94	1.6
Chevron	Conventional with CO Promoter	1.19	88	4.2
Chevron	--	0.45	67	5.0[c,e]
Mobil	HTR	1.27	72	10.0
Mobil	HTR	1.0	66	10.1
Texaco	HTR	1.26	57	15.1
API	Conventional with CO Promoter	1.16	41	20.0[f]
Davison	Conventional	0.48-0.58	45	11[c]
Davison	Conventional	0.48-0.58	58	8.5[c]
Davison	Conventional	0.56	66	7.1[c]
Davison	Conventional	0.52	55	9.0[c]
Davison	Conventional	0.48-0.58	80	4.0[c]

[a] Estimated percent reduction was obtained by comparing actual SO_x emissions with SO_x reduction catalysts in use to estimated baseline emissions. Estimated baseline emissions were obtained by using the average feed sulfur level during catalyst testing and the SO_x emissions/feed sulfur relationship found in Figure 3-6.

[b] Estimated percent emission reduction may include the effects of first generation SO_x reduction catalysts as well as the developmental SO_x reduction catalyst.

[c] Emissions originally reported in vppm were converted to kg/1,000 kg coke burn-off by using Figure 3-6.

[d] The low SO_x emission levels obtained during testing do not represent equilibrium conditions and do not indicate that long-term operation under these conditions would be feasible.

[e] Due to problems with the operation of the FCC unit which predated the test, SO_x reduction catalyst addition was terminated before the desired level of emission reduction was achieved.

[f] Unit was operated in the partial CO combustion mode. This may have affected the SO_x reduction capabilities of the SO_x reduction catalyst being evaluated.

In some instances, emissions of oxides of nitrogen (NO_x) have increased two to seven fold when operating the sulfur oxides reduction catalysts at high sulfur oxides reduction levels.[98] When NO_x emissions were controlled by altering the catalyst, problems with rapid deactivation of catalyst sulfur oxides retention capability[105] and yield debits (reductions in product quantity and quality) were encountered. Nitrogen oxides emissions data from FCC units operating with and without the sulfur oxides reduction catalysts were obtained in order to evaluate NO_x emissions increases due to the use of the catalysts. An analysis of these data showed that NO_x emissions increases resulting from use of these catalysts are not signficant. However, CO promoted conventional regeneration FCC units appear to have high NO_x emissions without sulfur oxides reduction catalysts, and even higher NO_x emissions with sulfur oxides reduction catalysts. The significance of this increase is unknown due to the limited number for sulfur oxides reduction catalyst emission tests performed.[113]

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5.0 MODIFICATION AND RECONSTRUCTION

In accordance with the provisions of Title 40 of the Code of Federal Regulations (CFR), Sections 60.14 and 60.15, an existing facility can become an affected facility and, consequently, subject to the standards of performance if it is modified or reconstructed. An "existing facility," defined in 40 CFR 60.2, is a facility of the type for which a standard of performance is promulgated and the construction or modification of which was commenced prior to the proposal date of the applicable standards. The following discussion examines the applicability of modification/reconstruction provisions to the fluid catalytic cracking unit regenerator.

5.1 GENERAL DISCUSSION OF MODIFICATION AND RECONSTRUCTION PROVISIONS

5.1.1 Modification

Modification is defined in §60.14 as any physical or operational change to an existing facility which results in an increase in the emission rate of the pollutant(s) to which the standard applies. Paragraph (e) of §60.14 lists exceptions to this definition which will not be considered modifications, irrespective of any changes in the emission rate. These changes include:

1. Routine maintenance, repair, and replacement,
2. An increase in the production rate not requiring a capital expenditure as defined in §60.2,
3. An increase in the hours of operation,
4. Use of an alternative fuel or raw material if, prior to proposal of the standard, the existing facility was designed to accommodate that alternative fuel or raw material,
5. The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or replaced by a system considered to be less environmentally beneficial,

6. The relocation or change in ownership of an existing facility.

As stated in paragraph (b), emission factors, material balances, continuous monitoring systems, or manual emission tests are to be used to determine emission rates expressed as kg/hr of pollutant. Paragraph (c) affirms that the addition of an affected facility to a stationary source through any mechanism -- new construction, modification, or reconstruction -- does not make any other facility within the stationary source subject to standards of performance. Paragraph (f) provides for superseding any conflicting provisions. And, (g) stipulates that compliance be achieved within 180 days of the completion of any modification.

5.1.2 Reconstruction

Under the provisions of §60.15, an existing facility becomes an affected facility upon reconstruction, irrespective of any change in emission rate. Reconstruction is the replacement of components of an existing facility to such an extent that: (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards of performance. When the replacement of components of an existing facility meets the cost criterion for reconstruction, the Administrator of the EPA shall determine whether the replacement constitutes reconstruction. As stated in §60.15(f), the Administrator's determination of reconstruction will be based on:

> (1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable new facility; (2) the estimated life of the facility after the replacements compared to the life of a comparable entirely new facility; (3) the extent to which the components being replaced cause or contribute to the emissions from the facility; and (4) any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

The purpose of the reconstruction provision is to ensure that an owner or operator does not perpetuate an existing facility by replacing all but minor components, support structures, frames, housing, etc., rather than totally replacing it in order to avoid being subject to applicable performance standards. In accordance with §60.5, EPA will, upon request, determine if an action taken constitutes reconstruction.

5.2 APPLICABILITY OF MODIFICATION PROVISIONS TO FCC REGENERATORS

Several changes, either physical or operational, that could be encountered while expanding or modernizing an existing FCC unit are presented below along with the anticipated effect on sulfur oxides emissions.

5.2.1 Maintenance, Repair, and Replacement

Maintenance, repair, and component replacement which are considered routine for a source category irrespective of any changes in sulfur oxides emissions are not considered modifications under §60.14(e)(1). An increase in sulfur oxides emissions is not expected to occur as a result of normal maintenance or replacement of FCC regenerator components.

The FCC regenerator usually operates for 2 to 6 years continuously before maintenance, repair, or replacement of internal components is necessary.[1,2] After this time, the unit is shut down and purged so that the regenerator can be inspected for wear. This procedure is called a turnaround. During the 2 to 4 week turnaround period, routine maintenance or repairs may be required due to the erosion of internal surfaces by catalyst particles or to the build-up of coke deposits on certain components.[3] Routine maintenance or repair performed during an FCC unit regenerator turnaround may include inspecting and, if necessary, repairing the air distribution system, standpipe, slide valves, plenum chamber, catalyst overflow weir, and regenerator grid and seals. The regenerator refractory lining is also inspected for wear and patched, if necessary.[4] Routine maintenance and repair of the FCC regenerator would normally be expected to decrease or have no effect on sulfur oxides emissions.

FCC unit regenerator internal components may require periodic replacement due to excessive erosion or corrosion of internal surfaces. For example, the regenerator internal cyclones may be replaced after a typical service life of 10 years.[3] If the cyclones are replaced with equivalent cyclones, particulate emissions usually decrease due to the increased catalyst capture efficiency of the new cyclones. However, the new cyclones are not expected to affect sulfur oxides emissions from the FCC unit regenerator. Cyclone replacement may contribute to the cost of reconstruction. This is discussed in Section 5.3.

5.2.2 Increasing Capacity

An increase in capacity is not considered a modification under §60.14 if the increase can be accomplished without incurring a capital expenditure on the existing facility. A capital expenditure is defined as "an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable 'annual asset guideline repair allowance percentage' specified in the latest edition of Internal Revenue Service Publication 534 and the existing facility's basis, as defined by Section 1012 of the Internal Revenue Code" (40 CFR, §60.2).

A refiner may decide to increase the capacity of an existing FCC unit to improve the yield pattern of certain products, meet product demands, and increase profitability. FCC unit capacity may be increased by increasing the regenerator combustion air flow rate, increasing the regenerator internal pressure, or through oxygen enrichment of the regenerator combustion air.[5] These changes may be achieved without a capital expenditure as defined by Section 1012 of the Internal Revenue Code.

In many cases FCC unit capacity is determined by the quantity of coke which can be burned off within the regenerator. A common technique employed by a refiner to increase FCC unit capacity is to install an additional blower to the unit's air distribution system. The additional blower increases the quantity of combustion air which moves through the catalyst bed and increases catalyst coke burn-off rate. This allows more catalyst to be fed to the riser reactor and increases the quantity of fresh feed that can be processed. An alternate means of increasing regenerator coke burn-off capacity is through oxygen enrichment of the regenerator combustion air.[5] The increased coke burn-off rate may result in an increase in sulfur oxides emissions. The increased air flow rate requires increased gas handling capacity in the regenerator cyclones and more downstream flue gas handling equipment, such as coolers and precipitators.[6]

FCC unit fresh feed capacity may be increased by reducing the coke make rate especially when the unit is air blower limited, or by reducing the amount of recycle oils processed in the unit. The coke make rate can be reduced by processing high quality feedstocks or by hydrotreating. Catalyst selection, improved regeneration, and decreased conversion all reduce the coke make rate. Recycle may be reduced or eliminated through catalyst selection, increased conversion, or through alternate use of recycle oils instead of reinjection into the FCC unit. These changes would allow the refiner to increase FCC unit fresh feed capacity.

FCC unit capacity can also be increased by increasing the regenerator internal pressure. The results of the increased internal pressure are similar to that of increasing regenerator combustion air flow rate. The increased regenerator internal pressure allows more combustion air to come in contact with the catalyst and increases the catalyst coke burn-off rate. The increased coke burn-off rate may result in an increase in sulfur oxides emissions. Regenerator internal pressure is increased by modifying the compression equipment through rotor or blade replacement, or through addition of a booster compressor upstream or downstream from the existing compressor. In addition, a refiner may install thin internal liners in the regenerator to reduce the metal temperature of the shell.[6]

5.2.3 Increase in Hours of Operation

An increase in emissions from an existing facility due to an increase in the hours of operation is not considered a modification under §60.14(e)(3). FCC units operate, on average, 24 hours per day, 365 days per year. An exception to this is when the unit is shut down for maintenance. It is unlikely that refiners would alter the hours of operation of their FCC units.

5.2.4 Change in FCC Feedstock Quality

Changes in FCC feedstock quality, such as a change to higher sulfur content feeds, a change to a higher contaminant metals content feed, or an increase in recycle rate, may result in an increase in sulfur oxides emissions from the FCC unit regenerator. Changes in the crude supply or product demand may necessitate a change in feedstock quality. A change to a higher sulfur content feed may not only increase regenerator sulfur oxides emissions, but also result in corrosion of certain regenerator internal components due to the higher sulfur levels present in the gases contained within the regenerator. A change in sulfur oxides emissions which results from a change in feedstock quality is not considered a modification provided the existing facility was designed to accommodate that feedstock.

For a specific feedstock and unit throughput, hydrodesulfurization will decrease the sulfur oxides emissions from the FCC unit regenerator. In general, HDS can remove the sulfur from high sulfur feeds and decrease sulfur oxides emissions from the regenerator.[7] However, HDS can also increase the yields of certain desirable products and improve overall feed cracking characteristics.[8] This may enable a refiner to increase unit capacity or process higher sulfur feeds and thus increase regenerator sulfur oxides emissions.

5.2.5 Addition, Removal, or Disabling of a System to Control Air Pollutants

The addition or use of any system or device whose primary function is to reduce air pollutants, except the replacement of such a system or device by a less efficient one, is not considered a modification under §60.14.

The intentional removal or disabling of any emission control component of an existing FCC unit regenerator which would cause an increase in sulfur oxides emissions would be a modification.

5.3 APPLICABILITY OF RECONSTRUCTION PROVISIONS TO FCC REGENERATORS

FCC units operate for long periods of time without major servicing. Many units installed in the early 1940's are still operational. There are only a few expansions or modernizations to the FCC regenerator which may contribute to the cost of reconstruction.

5.3.1 Conversion to High Temperature Regeneration

An action that might be considered as a reconstruction of the FCC unit regenerator is the conversion to high temperature regeneration (HTR). HTR revamping of an FCC regenerator generally requires the replacement of cyclones, the plenum chamber, cyclone diplegs, the regenerator grid and seals, and the catalyst overflow weir. These components must be constructed from stainless steel rather than carbon steel in order to withstand the higher temperatures.[9] It is possible that an HTR revamp may exceed 50 percent of the capital cost to construct an entirely new FCC unit regenerator.

5.3.2 Addition or Replacement of Regenerator Combustion Air Blower, Cyclones, or Other Regenerator Internal Components

Although the addition or replacement of regenerator combustion air blowers, internal cyclones, or other internal components was discussed in Sections 5.2.1 and 5.2.2 under Modification, this activity may contribute to the reconstruction of an FCC unit regenerator. The cost of a major turnaround may exceed 50 percent of the capital cost of a new FCC regenerator.

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6.0 MODEL PLANTS AND REGULATORY ALTERNATIVES

The purpose of this chapter is to define model plants and identify regulatory alternatives. Model plants are parametric descriptions of types of plants that, in EPA's judgment, will be constructed, modified, or reconstructed. The model plant parameters are used as a basis for estimating the environmental, economic, and energy impacts associated with the application of regulatory alternatives to the model plants.

6.1 MODEL PLANTS

Each FCC unit and, hence, each regenerator is unique from a technical standpoint. FCC unit types and sizes, flow rates, feedstock quality, regeneration mode, recycle rates, air flow rates, and emission rates vary from one unit to another. For this reason, no single model plant can adequately characterize the FCC units. Accordingly, several model FCC units were specified in terms of some appropriate parameters to span the range of anticipated FCC unit sizes, feedstock quality, flow rates, and emissions.

Table 6-1 lists model FCC unit parameters used in the environmental, energy, cost, and economic analyses of the regulatory alternatives. A total of six model FCC units have been selected. Model FCC units are based primarily on FCC unit capacity and on the sulfur content of the regenerator flue gas. Two different flue gas flow rates and three different flue gas sulfur oxides concentrations were chosen to represent typical ranges of processing capacity and feed sulfur.

The selection of model FCC unit parameters is based on published literature, information obtained during plant visits, and calculations. Model unit capacities are identified on the basis of current and historical FCC construction, as described in Appendix E. The two selected capacities, 2,500 m^3/sd and 8,000 m^3/sd, are representative of FCC units which are presently being constructed or which have been

Table 6-1. MODEL FCC UNIT PARAMETERS[a]

				Exhaust Gas Composition and Flow Rates						
					Sulfur Oxides[c] Emissions		Particulate[d] Emissions			
FCC Fresh Feed Capacity (m^3/sd)	Recycle Rate (m^3/sd)	Feed Sulfur Content (wt%)	Coke Burn-off Rate[b] (kg/hr)	Air Flow Rate (sm^3/min)	(vppm)	($kg/10^3kg$ Coke Burn-off)	(kg/hr)	($kg/10^3kg$ Coke Burn-off)	Carbon Monoxide Content (vol. %)	Exhaust Gas Temperature[e] (°C)
2,500	375	0.3	4,702	954	400	13.0	47	10	0.05	200
		1.5	4,645	945	1,400	46.0	46	10	0.05	200
		3.5	4,546	934	2,700	88.0	45	10	0.05	200
8,000	1,200	0.3	15,064	3,056	400	13.0	150	10	0.05	200
		1.5	14,885	3,030	1,400	46.0	149	10	0.05	200
		3.5	14,562	2,991	2,700	88.0	146	10	0.05	200

[a] Assumes 5 wt. percent coke yield, a coke composition of 4 weight percent hydrogen, coke sulfur content from Figure 3-5, and the balance carbon, 2 percent excess oxygen in flue gas, and 500 vppm CO in flue gas.

[b] Calculations based on coke burn-off formula in 40 CFR 60.102, March 8, 1974.

[c] Sulfur oxides emissions reported as SO_2.

[d] Back calculated from controlled outlet emission rate of 1 kg/1000 kg coke burn-off, assuming 90 percent control.

[e] After heat recovery.

constructed in the last 10 years. Recycle rates are based on the current U.S. average FCC recycle capacity of approximately 15 percent of the fresh feed.[1]

Air flow rates and emissions are calculated by using the methods described in Chapter 3. Coke yield is assumed to be 5 weight percent of the fresh feed. Coke sulfur levels are identified by specifying the FCC feed sulfur content and by using the correlation between feed sulfur and coke sulfur (Figure 3-5). This correlation and thus model FCC unit sulfur oxides emissions are representative of actual FCC unit emissions for many common FCC feedstocks. Feed sulfur levels of 0.3, 1.5, and 3.5 weight percent are representative of low, intermediate, and high sulfur feeds, respectively.

The regenerator flue gas excess oxygen is assumed to be two volume percent and the carbon monoxide concentration is assumed to be 500 vppm. These values are consistent with current technologies for meeting the carbon monoxide emission requirements. Excluding the sulfur oxides emissions which would result from FCC units with carbon monoxide combustion furnaces firing sulfur-containing fuel, the three feeds yield regenerator flue gas sulfur oxides concentrations of 13 kg/1,000 kg coke burn-off, 46 kg/1,000 kg coke burn-off, and 88 kg/1,000 kg coke burn-off. These correspond to regenerator flue gas sulfur oxides concentrations of 400 vppm, 1,400 vppm, and 2,700 vppm, respectively. These emissions are calculated as sulfur dioxide and are dependent only on feed sulfur content. Changes in coke yield from 4.0 to 6.5 and greater weight percent of fresh feed do not result in significant variations in sulfur oxides emissions when reported as kg/1,000 kg coke burn-off or as vppm. Thus, sulfur oxides emissions reported as kg/1,000 kg coke burn-off or in vppm are independent of the coke yield.

Emissions of other pollutants including cyanides, ammonia, and nitrogen oxides are discussed in Chapter 3. Since these emissions are a minor portion of the total FCC regenerator emissions, they are not specified as part of the model unit emissions.

6.2 REGULATORY ALTERNATIVES

Regulatory alternatives are possible courses of action that could be taken to reduce emissions from a source. In this case, regulatory alternatives identify sulfur oxides emission levels which FCC regenerators could achieve by using demonstrated control technologies. As discussed in Chapter 4, FCC sulfur oxides emissions may be reduced by using flue gas desulfurization (FGD) or sulfur oxides reduction catalysts. These control technologies form the bases for the emission levels defined by the regulatory alternatives. Hydrodesulfurization is a process used by refiners to improve product quality and yields. Due to the expense of hydrodesulfurization, it is expected that refiners will install these process units primarily for yield and quality improvements rather than sulfur oxides control. Therefore, hydrodesulfurization is not considered as a control technology for this analysis.

To assess the environmental, energy, and economic impacts of using FGD or sulfur oxides reduction catalysts to meet the regulatory alternatives, the affects of these control technologies on the FCC unit and its operation must be known. The impacts of using FGD are easily quantified due to the large body of literature on this subject. Also, sodium-based FGD systems have been installed on FCC regenerator flue gas streams, and they do not impact unit operations or product yields.

Sulfur oxides reduction catalysts are an emerging technology which have not been used in long-term commercial operations. Their effects on product yield, sulfur plant operation, and emissions have not been completely determined. Impact analyses for this control technology may thus contain significant uncertainties.

To reduce the uncertainty involved in calculating the impacts of each model plant and regulatory alternative combination, the impacts will be evaluated based on the use of sodium-based FGD systems alone to meet the regulatory alternatives. Although the emission levels for the regulatory alternatives are based on the performance of sulfur oxides reduction catalysts and flue gas desulfurization, impacts are evaluated by assuming that the FGD system reduces model plant sulfur oxides emissions to the levels defined by the regulatory alternatives. These levels of scrubbing represent the amount by which model plant sulfur oxides emissions must be reduced to meet each regulatory alternative.

Four regulatory alternatives have been selected. These are illustrated graphically in Figure 6-1. Each regulatory alternative,

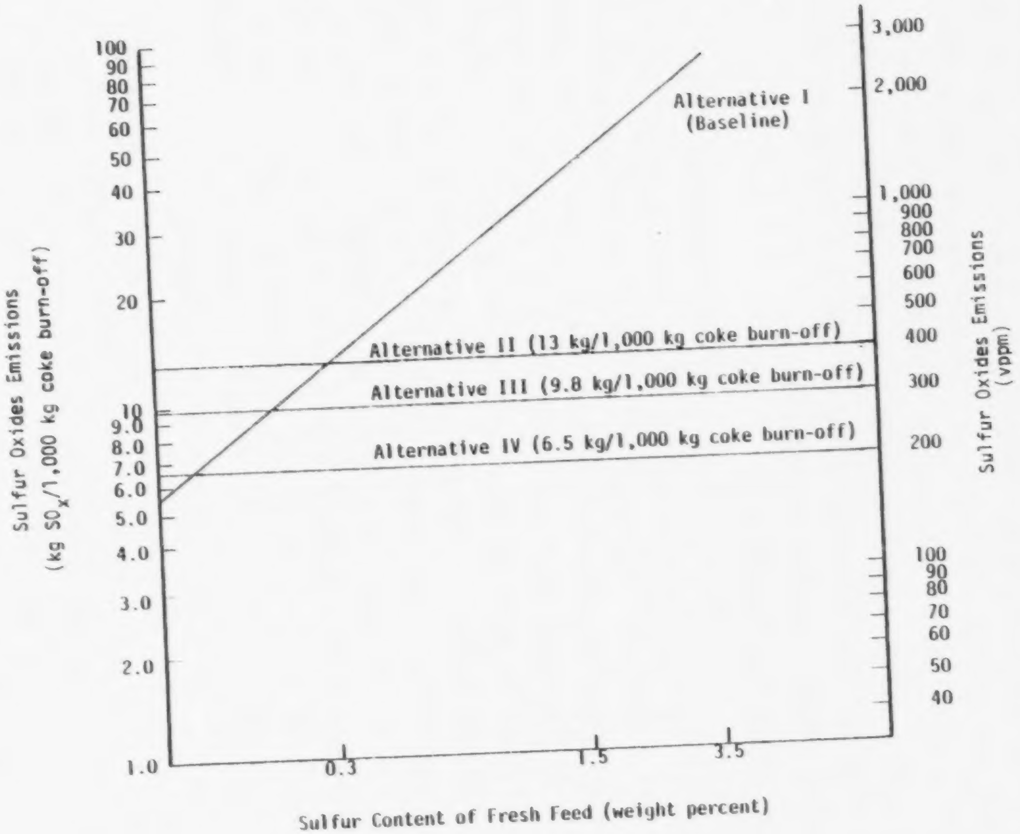

Figure 6-1. Regulatory Alternatives

its technological basis, and level of scrubbing is discussed in the following sections.

6.2.1 Regulatory Alternative I - The Baseline Level

Baseline control is defined as the level of emission reduction currently achieved by an industry and is typically dictated by State or local regulations. As discussed in Chapter 3, the baseline level represents the level of control required for existing FCC units to be in compliance with most State and local sulfur oxides regulations. The baseline level (Alternative I) is illustrated in Figure 6-1. Baseline sulfur oxides emissions range from 13 to 88 kg/1,000 kg coke burn-off (400 to 2,700 vppm) for commonly used FCC feedstocks of 0.3 to 3.5 weight percent sulfur, respectively.

6.2.2 Regulatory Alternative II

Regulatory Alternative II would require that sulfur oxides emissions from FCC units be limited to 13 kg sulfur oxides/1,000 kg coke burn-off (400 vppm). The equivalent levels of scrubbing required to meet Regulatory Alternative II are: 85 percent for the 3.5 weight percent sulfur feedstock model units to reduce flue gas sulfur oxides content from 88 to 13 kg/1,000 kg coke burn-off (2,700 to 400 vppm), 71 percent for the 1.5 weight percent sulfur feedstock model units to reduce flue gas sulfur oxides content from 46 to 13 kg/1,000 kg coke burn-off (1,400 to 400 vppm), and little or no scrubbing for the 0.3 weight percent sulfur feedstock model units whose baseline sulfur oxide emissions are 13 kg/1,000 kg coke burn-off (400 vppm). The economic, environmental, and energy impacts for Regulatory Alternative II will be determined based on these levels of scrubbing.

The basis for this alternative is to allow refiners an opportunity to use sulfur oxides reduction catalysts to meet this regulatory alternative. Depending upon the sulfur levels of FCC unit feeds charged to their units, most refiners will be able to utilize the sulfur oxides reduction catalyst technology, while a few may use flue gas desulfurization. The emerging sulfur oxides reduction catalyst technology can be used to meet Regulatory Alternative II when feeds up to approximately 2.3 weight percent sulfur are charged to the FCC unit.

6.2.3 Regulatory Alternative III

Regulatory Alternative III would require that sulfur oxides emissions from FCC units be limited to 9.8 kg sulfur oxides/1,000 kg coke burn-off (300 vppm). The levels of scrubbing required to meet Regulatory Alternative III are: 89 percent for the 3.5 weight percent sulfur feedstock model units to reduce flue gas sulfur oxides content from 88 to 9.8 kg/1,000 kg coke burn-off (2,700 to 300 vppm), 79 percent for the 1.5 weight percent sulfur feedstock model units to reduce flue gas sulfur oxides content from 46 to 9.8 kg/1,000 kg coke burn-off (1,400 to 300 vppm), and 25 percent for the 0.3 weight percent sulfur model units to reduce flue gas sulfur oxides emissions from 13.0 to 9.8 kg/1,000 kg coke burn-off (400 to 300 vppm). The energy, economic, and environmental impacts of Regulatory Alternative III will be determined based on these levels of scrubbing.

As with Alternative II, the basis for this alternative is to allow refiners an opportunity to use sulfur oxides reduction catalysts to meet this regulatory alternative. Depending on the sulfur levels of FCC unit feeds charged to their units, most refiners are expected to utilize the sulfur oxides reduction catalyst technology, while a few may use flue gas desulfurization. The emerging sulfur oxides reduction catalyst technology can be used to meet this alternative when feeds up to about 1.7 weight percent sulfur are charged to the FCC unit.

6.2.4 Regulatory Alternative IV

Regulatory Alternative IV would require that sulfur oxides emissions from FCC units be limited to 6.5 kg sulfur oxides/1,000 kg coke burn-off (200 vppm). The levels of scrubbing required to meet Regulatory Alternative IV are: 93 percent for the 3.5 weight percent sulfur feedstock model units to reduce flue gas sulfur oxides emissions from 88 to 6.5 kg/1,000 kg coke burn-off (2,700 to 200 vppm), 86 percent for the 1.5 weight percent sulfur feedstock model units to reduce flue gas sulfur oxides emissions from 46 to 6.5 kg/1,000 kg coke burn-off (1,400 to 200 vppm), and 50 percent for the 0.3 weight percent sulfur feedstock model units to reduce sulfur oxides emissions from 13 to 6.5 kg/1,000 kg coke burn-off (400 to 200 vppm). The energy, economic, and environmental impacts of Regulatory Alternative IV are based on these levels of scrubbing.

This alternative is based on the use of sodium-based flue gas scrubbing. This alternative can be met on a continuous basis, over the entire range of expected feed sulfur content, by a properly operating and maintained flue gas scrubber. It is expected that refiners whose FCC units are processing feeds containing approximately 1.0 weight percent sulfur or less may be able to use sulfur oxides reduction catalysts to meet Regulatory Alternative IV.

Table 6-2 presents a summary of the model units, the regulatory alternatives, and the equivalent scrubbing levels for each regulatory alternative.

Table 6-2. SUMMARY OF REGULATORY ALTERNATIVES

Regulatory Alternative	Model Unit Size (m^3/sd)	Feed Sulfur Level (wt. %)	Sulfur Oxides Emissions kg/1000 kg coke burn off (vppm) Uncontrolled	Sulfur Oxides Emissions kg/1000 kg coke burn off (vppm) Control Level	Equivalent Scrubbing Level
I (Baseline)	2,500 and 8,000	0.3	13 (400)	--	0
		1.5	46 (1,400)	--	0
		3.5	88 (2,700)	--	0
II	2,500 and 8,000	0.3	13 (400)	13 (400)	0
		1.5	46 (1,400)	13 (400)	71
		3.5	88 (2,700)	13 (400)	85
III	2,500 and 8,000	0.3	13 (400)	9.8 (300)	25
		1.5	46 (1,400)	9.8 (300)	79
		3.5	88 (2,700)	9.8 (300)	89
IV	2,500 and 8,000	0.3	13 (400)	6.5 (200)	50
		1.5	46 (1,400)	6.5 (200)	86
		3.5	88 (2,700)	6.5 (200)	93

6.3 REFERENCES

1. Cantrell, A. Annual Refining Survey. Oil and Gas Journal. 78(12):130-157. March 24, 1980. Docket Reference Number II-I-71.*

*References can be located in Docket Number A-79-09 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

7.0 ENVIRONMENTAL IMPACTS

7.1 INTRODUCTION

Sodium-based scrubbing is the demonstrated control technology applied to FCC units, and it is expected that this would be the most widely applicable control system upon implementation of a regulatory alternative. As such, the environmental impacts analyses are focused upon sodium-based scrubbing. However, refiners may opt to utilize alternative control technologies as discussed in Chapter 4.0. These other control technologies may be an attractive alternative to sodium-based scrubbing particularly for FCC units at refineries where water availability or wastewater discharges are restricted. In Section 7.4, the environmental impacts for other control technologies are discussed and compared to sodium-based scrubbing. The environmental impacts for all of the other control technologies are based on the same parameters as the sodium-based scrubber systems. Table 6-2 lists the sulfur oxides emissions levels for the regulatory alternatives which serve as the basis for the analyses.

The focus of this analysis is to determine the incremental increase or decrease over the baseline control level in air pollution, water pollution, solid waste, and energy impacts of the regulatory alternatives. The baseline control level reflects existing levels of control of FCC unit sulfur oxides emissions as required by State and local regulations. This level is represented by Regulatory Alternative I.

This chapter first addresses the air pollution impacts of implementing each of the regulatory alternatives. The sulfur oxides emission reductions are independent of the control technology applied, and, therefore, sodium-based scrubbing as well as other control technologies would result in the same reductions. Water pollution, solid waste, and energy impacts for sodium-based scrubbing are addressed in

Sections 7.3.1, 7.3.2, and 7.3.3, respectively. The environmental impacts associated with other control technologies are discussed in Section 7.4.

7.2 AIR POLLUTION IMPACTS OF REGULATORY ALTERNATIVES

The following discussion on air pollution impacts pertains to the application of each control technology discussed in Chapter 4.0. In addition to sodium-based scrubbing, these controls include dual alkali, Wellman-Lord, citrate, spray drying, and use of sulfur oxides reduction catalysts.

7.2.1 Primary Air Pollution Impacts

Emissions from model FCC units include particulate matter, sulfur oxides, and carbon monoxide. Since particulate and carbon monoxide emissions are already controlled by new source performance standards (NSPS), only sulfur oxides emissions are discussed here.

Annual sulfur oxides emissions and emission reductions by regulatory alternative for the model units are presented in Table 7-1. Annual sulfur oxides emissions from model units range from 260 to 11,100 megagrams per year; emission reductions from the baseline level range from zero to 93 percent depending on regulatory alternative and model unit.

7.2.2 Secondary Air Pollution Impact

Secondary air pollutants which result from the use of pollution control equipment are not usually associated with an uncontrolled facility. No secondary air pollution problems are anticipated due to the application of sodium-based or other scrubbers to FCC unit regenerators.

In some instances, nitrogen oxides (NO_x) emissions from FCC units increased when operated with sulfur oxides reduction catalysts in place. Nitrogen oxides emission data from FCC units operating with and without the sulfur oxides reduction catalysts were obtained in order to evaluate NO_x emissions increases due to the use of the catalysts. An analysis of these data showed that NO_x emissions increases resulting from use of these catalysts are not significant However, CO promoted conventional regeneration FCC units appear to have high NO_x emissions without sulfur oxides reduction catalysts and even higher NO_x emissions with sulfur oxides reduction catalysts. The significance of this increase is unknown due to the limited number of SO_x reduction catalyst tests performed.[1]

Table 7-1. ANNUAL SULFUR OXIDES EMISSIONS AND EMISSION REDUCTIONS FOR EACH REGULATORY ALTERNATIVE[a]

Regulatory Alternative	Model Unit Size (m^3/sd)	Fresh Feed Sulfur Content (wt. %)	Annual Sulfur Oxides Emissions[b] (Mg/yr)	Annual Reductions in Sulfur Oxides Emissions from Baseline (Mg/yr)	Percent Reduction from Baseline
I (Baseline)	2,500	0.3	520	-	0
		1.5	1,860	-	0
		3.5	3,480	-	0
	8,000	0.3	1,650	-	0
		1.5	5,950	-	0
		3.5	11,100	-	0
II	2,500	0.3	520	0	0
		1.5	520	1,340	71
		3.5	520	2,970	85
	8,000	0.3	1,650	0	0
		1.5	1,650	4,290	71
		3.5	1,650	9,500	85
III	2,500	0.3	390	130	25
		1.5	390	1,470	79
		3.5	390	3,100	89
	8,000	0.3	1,240	410	25
		1.5	1,240	4,710	79
		3.5	1,240	9,910	89
IV	2,500	0.3	260	260	50
		1.5	260	1,600	86
		3.5	260	3,230	93
	8,000	0.3	830	830	50
		1.5	830	5,120	86
		3.5	830	10,300	93

[a] Assumes that the FCC unit operates 357 days per year, 24 hours per day. Sulfur oxides emissions calculated on the basis of 400 vppm for feed sulfur content of 0.3 weight percent, 1,400 vppm for feed sulfur content of 1.5 weight percent, and 2,700 vppm for feed sulfur content of 3.5 weight percent.

[b] Total sulfur oxides calculated as SO_2.

7.2.3 Dispersion Modeling

Mathematical modeling of the ambient air is used to predict the concentration of sulfur oxides in the atmosphere at various distances from model FCC units. This analysis of pollutant dispersion enables assessment of the effect of each regulatory alternative on air quality near the FCC unit. All modeling was conducted using the CRSTER model. Since FCC units are likely to be located in urban/refinery areas characterized by considerable surface roughness and heating from combustion sources, the urban mode of the model was used. Emission concentrations were examined at distances from 0.1 to 10 km downwind of the FCC unit to determine the maximum dispersion impacts. Other input variables used in the model appear in Table 7-2. For the baseline cases (Regulatory Alternative I and Regulatory Alternative II for units charging 0.3 weight percent sulfur feedstocks), the model FCC parameters are based on the use of electrostatic precipitators (required for particulate control), whereas all other cases use sodium-based scrubbing. Dispersion modeling results are shown in Table 7-3.[28]

The results of the dispersion modeling indicate that the application of scrubbers to FCC units may increase ground level concentrations of sulfur oxides. Scrubber stack gases are cooler and have a lower plume rise than the baseline case and therefore, increased ground level concentration of sulfur oxides. From Table 7-3, 1- and 3-hour maximum ground level sulfur oxides concentrations are higher for Alternative III than Alternative I (the baseline case) for an FCC unit processing a 0.3 weight percent sulfur feedstock. The increase in ground level sulfur oxides concentrations due to scrubbers may be mitigated through use of greater stack heights or exit velocities than those specified for the model plants in Table 7-2.

Prevention of significant deterioration (PSD) increments are presented in Table 7-3 to allow comparisons with the dispersion modeling results. Based on these results, PSD regulations would preclude the construction of new FCC units in Class I (pristine) air quality areas regardless of regulatory alternative. Modeling results show that FCC units meeting Alternative II, III, or IV and all but those FCC units processing high sulfur feeds under Alternative I could operate in PSD

Table 7-2. PARAMETERS FOR MODEL FCC UNIT REGENERATOR DISPERSION MODEL ANALYSIS

FCC Fresh Feed Capacity (m^3/sd)	Regulatory Alternative	Feed Sulfur Content (Weight Percent)	Stack Exit Temperature (°K)	Sulfur Oxides Emission Rate[a] (g/s)	Stack Height (m)	Stack Diameter (m)	Stack Exit Velocity (m/s)
2,500	I, II	0.3	473	17	46	1.3	11.2
	I	1.5	473	60	46	1.3	11.2
	I	3.5	473	113	46	1.3	11.2
	II	1.5,3.5	340	17	68	1.2	16.2
	III	0.3,1.5,3.5	340	13	68	1.2	16.2
	IV	0.3,1.5,3.5	340	8	68	1.2	16.2
8,000	I, II	0.3	473	54	57	2.6	9.4
	I	1.5	473	193	57	2.6	9.4
	I	3.5	473	360	57	2.6	9.4
	II	1.5,3.5	340	54	68	2.2	16.2
	III	0.3,1.5,3.5	340	40	68	2.2	16.2
	IV	0.3,1.5,3.5	340	27	68	2.2	16.2

[a] Reported as SO_2.

Table 7-3. RESULTS OF DISPERSION MODELING FOR SULFUR OXIDES EMISSIONS FROM MODEL FCC UNITS AND PSD INCREMENTS[a]

FCC Fresh Feed Capacity (m^3/sd)	Regulatory Alternative	Feed Sulfur Content (weight percent)	Sulfur Oxides Emission Rate[b] (g/s)	Maximum Ground Level Sulfur Oxides Concentrations[b] (in g/m^3) and Distance (in km) Downwind from Source							
				1-Hour Maximum		3-Hour Maximum		24-Hour Maximum		Annual Maximum	
				Concentration	Distance	Concentration	Distance	Concentration	Distance	Concentration	Distance
2,500	I,II	0.3	17	102	0.6	78	0.5	23	2.0	2.5	2.0
	I	1.5	60	361	0.6	274	0.5	81	2.0	8.8	2.0
	I	3.5	113	680	0.6	517	0.5	152	2.0	17	2.0
	II	1.5,3.5	17	198	0.6	113	0.6	20	0.6	2.0	2.0
	III	0.3,1.5,3.5	13	151	0.6	86	0.6	16	0.6	1.5	2.0
	IV	0.3,1.5,3.5	8	93	0.6	53	0.6	10	0.6	0.9	2.0
8,000	I, II	0.3	54	137	1.0	82	1.0	26	3.0	2.1	3.0
	I	1.5	193	491	1.0	291	1.0	91	3.0	7.7	3.0
	I	3.5	360	916	1.0	543	1.0	170	3.0	14	3.0
	II	1.5,3.5	54	253	0.6	145	0.5	30	3.0	3.2	3.0
	III	0.3,1.5,3.5	40	188	0.6	107	0.5	22	3.0	2.4	3.0
	IV	0.3,1.5,3.5	27	127	0.6	72	0.5	15	3.0	1.6	3.0
PSD Increments	Class I					25		5		2	
	Class II					512		91		20	
	Class III					700		182		40	

[a] Reference 28.

[b] Reported as SO_2.

Class II areas. FCC units could operate in PSD Class III areas regardless of regulatory alternative.

Sulfur oxides emissions under all regulatory alternatives are in compliance with national ambient air quality standards (NAAQS). Primary NAAQS limit annual concentrations to 80 micrograms/m^3 (arithmetic mean), and secondary NAAQS to 1,300 micrograms/m^3 maximum for any 3-hour period. The modeled FCC unit maximum ground level sulfur oxides concentration is realized by an 8,000 m^3/sd model unit charging a 3.5 weight percent sulfur feedstock. In this worst case, the modeled 3-hour and annual maximum sulfur oxides emissions are 14 mg/m^3 at 3 km downwind of the FCC unit and 543 mg/m^3 1 km downwind of the FCC unit, respectively.

7.2.4 Five-Year Impacts of Regulatory Alternatives

The projected number of affected new and modified/reconstructed model FCC units are presented by year in Tables 7-4 and 7-5. From historical FCC growth data presented in Appendix E, it is expected that 10 new FCC units will be constructed in this period. As shown in Table 7-4, units built in 1986 will probably be designed to process higher sulfur feeds than those built in 1982.

The available growth data, summarized in Appendix E, also indicate that up to 70 different units may increase throughput and emissions in a 5-year period. Many of these throughput and emission increases, however, occur as a result of normal unit turnarounds, routine maintenance, changes in feed availability, unit optimization, or construction not involving the FCC unit.[2-8] The actual number of units which modify or reconstruct thus may vary from only a few to 70. For the purposes of this analysis, it is estimated that 10 percent of the units which may increase capacity, 7 units, would be modified or reconstructed between 1982 and 1987.[9] Table 7-5 describes the projected distribution of modified/reconstructed facilities that is used in the impact analysis.

These growth projections are used to estimate future (1982 through 1986) impacts of the regulatory alternatives on sulfur oxides emissions. Future impacts are determined by applying the model unit emission rates in Table 7-1 to the projected distribution of affected facilities from Tables 7-4 and 7-5. The resulting annual impacts are presented by regulatory alternative in Table 7-6.

Table 7-4. PROJECTED NEW FCC UNIT CONSTRUCTION SCHEDULE[a]

Year	FCC New Unit Fresh Feed Capacity (m^3/sd)	Sulfur Content (wt %)	Uncontrolled Flue Gas Sulfur Oxides Concentration[b] (vppm)
1982	2,500	0.3	400
	8,000	0.3	400
1983	2,500	1.5	1,400
	8,000	1.5	1,400
1984	2,500	1.5	1,400
	8,000	1.5	1,400
1985	2,500	1.5	1,400
	8,000	1.5	1,400
1986	2,500	3.5	2,700
	8,000	3.5	2,700

[a] FCC unit growth projections are discussed in Appendix E.

[b] Total sulfur oxides reported as SO_2.

Table 7-5. PROJECTED FCC UNIT MODIFICATION/RECONSTRUCTION SCHEDULE[a]

Year	Modified/Reconstructed FCC Unit Fresh Feed Capacity (m^3/sd)	Sulfur Content (wt. %)	Uncontrolled Flue Gas Sulfur Oxides Concentration[b] (vppm)
1982	8,000	1.5	1,400
1983	2,500[c]	1.5	1,400
	8,000[c]	1.5	1,400
1984	8,000	1.5	1,400
1985	2,500	1.5	1,400
	8,000	1.5	1,400
1986	8,000	3.5	2,700

[a] FCC unit growth projections are discussed in Appendix E.

[b] Total sulfur oxides reported as SO_2.

[c] This modified/reconstructed FCC unit is assumed to have a carbon monoxide boiler.

Table 7-6. ANNUAL IMPACTS OF REGULATORY ALTERNATIVES ON SULFUR OXIDES EMISSIONS FROM NEW AND MODIFIED/RECONSTRUCTED FCC UNITS[a]

Regulatory Alternative	Year	Number of New and Modified/ Reconstructed Units	Annual Sulfur Oxides Emissions (Mg/yr)	Annual Sulfur Oxides Emissions Reduction (Mg/yr)
I (Baseline)	1982	3	8,120	-
	1983	7	23,700	-
	1984	10	37,500	-
	1985	14	53,100	-
	1986	17	78,800	-
II	1982	3	3,820	4,300
	1983	7	8,160	15,500
	1984	10	12,000	25,500
	1985	14	16,300	36,800
	1986	17	20,100	58,700
III	1982	3	2,870	5,250
	1983	7	6,130	17,600
	1984	10	9,000	28,500
	1985	14	12,300	40,900
	1986	17	15,100	63,800
IV	1982	3	1,920	6,200
	1983	7	4,100	19,600
	1984	10	6,020	31,500
	1985	14	8,200	44,900
	1986	17	10,100	68,700

[a] Total sulfur oxides reported as SO_2.

In the fifth year, total sulfur oxides emission reductions for new and modified/reconstructed FCC units range from zero for Regulatory Alternative I to 68,700 Mg for Regulatory Alternative IV.

7.3 OTHER ENVIRONMENTAL IMPACTS OF THE REGULATORY ALTERNATIVES

7.3.1 Water Pollution Impacts of Sodium-based Scrubbers

7.3.1.1 Quality and Quantity of Liquid Waste Discharges. The application of sodium-based scrubbers for control of sulfur oxides results in a wastewater discharge which must be treated and disposed. The scrubber effluent contains catalyst fines as suspended particulate and sodium salts (sodium sulfite, sodium sulfate, sodium bisulfite) as dissolved solids. Presently, the scrubber effluent from systems in operation on FCC regenerators is treated to adjust pH imbalances by alkali addition. Oxidation and settling tanks are used to reduce chemical oxygen demand and solids content of the waste stream prior to discharge.[10,11]

The scrubber system controls both particulate and sulfur oxides emissions. Except for alkali consumption, scrubber operation and the volume of wastewater discharged will remain approximately constant to maintain particulate removal efficiencies. Therefore, model unit throughput rather than sulfur content of the flue gas or regulatory alternative affects the volume of scrubber effluent to be disposed.

The quantity of wastewater discharged from sodium-based scrubbers is about 0.07 m^3/m^3 fresh feed.[10] The scrubber effluent, treated as described previously, is assumed to contain 5 weight percent dissolved solids as reported for sodium-based scrubbers in industrial boiler applications.[11] For FCC unit applications, the percentage of dissolved solids in the scrubber effluent is reported by the vendor to be proportional to the sulfur content of the flue gas. One refiner reports that the treated purge stream contains 40 g/m^3 suspended solids, and chemical oxygen demand of 40 g/m^3.[10] However, the vendor claims that the purge treatment is designed to reduce the total dissolved solids and chemical oxygen demand of the purge stream to 100 g/m^3 and 50 g/m^3, respectively.[12] A description of wastewater discharges from the model units is developed based on the reported refinery effluent discharges.

Discharges from the two model unit sizes are presented in Table 7-7. For these model units, annual scrubber discharges to receiving waters

Table 7-7. AQUEOUS DISCHARGES FROM FCC UNIT SODIUM-BASED SCRUBBER SYSTEMS

FCC Fresh Feed Capacity (m^3/sd)	Wastewater Discharge[a] (m^3/yr)	Suspended Solids[b] (Mg/yr)	Dissolved Solids[c] (Mg/yr)	Chemical Oxygen Demand[b] (Mg/yr)
2,500	62,500	2.5	3,100	2.5
8,000	200,000	8.0	10,000	8.0

[a] Assumes a linear relationship between discharge and flue gas flow rates. Calculated on the basis of 0.07 m^3 of wastewater discharge per m^3 of fresh feed, 357 days of operation per year. Reference 10.

[b] Reference 10.

[c] Reference 11. Dissolved solids represent approximately 5 weight percent of the wastewater discharge. To calculate mass discharge of dissolved solids, the density of the wastewater is assumed to be 1 Mg/m^3.

range from 62,500 to 200,000 m^3/yr, suspended solids discharges range from 2.5 to 8.0 Mg/yr, dissolved solids discharges range from 3,100 to 10,000 Mg/yr, and chemical oxygen demand ranges from 2.5 to 8.0 Mg/yr for the 2,500 and 8,000 m^3/sd model units, respectively.

7.3.1.2 Disposal Techniques. The five refineries with sodium-based scrubbers in operation for FCC unit sulfur oxides control are in or near coastal locations. The scrubber effluent is treated to reduce chemical oxygen demand, suspended solids content, and to adjust pH as described previously. The effluent is then discharged to large rivers or coastal waters. The dissolved solids content of the treated scrubber effluent is approximately 5 percent.[10] Because of this, discharge of the treated wastes to surface water may be restricted, especially in inland locations, due to refinery discharge permits. However, discharge of scrubber effluents to surface water may still be possible. If a sufficient volume of wastewater from elsewhere in the refinery is available and of low dissolved solids content, the dissolved solids content of the scrubber wastewater may be diluted to within permit limitations. Refinery effluent flows range from 1.2 to 6.0 m^3 of wastewater/m^3 crude charge.[13]

Alternatives to discharge of the treated wastes to surface water include discharge to municipal wastewater treatment facilities or evaporation ponds. These are popular alternatives for industrial boiler applications. Other alternatives include deep well injection, flash evaporation, or reverse osmosis. These latter alternatives are not widely used in boiler applications at present[11] and, therefore, may not gain acceptance for FCC unit applications.

7.3.1.3 Applicable Regulations. The applicable regulations relative to scrubber wastewater discharges are dependent upon the disposal technique being used. Discharges to receiving streams, territorial seas, or oceans must satisfy the requirements of National Pollution Discharge Elimination System (NPDES) and Ocean Discharge Criteria under the Water Pollution Control Act. Discharges to publicly owned treatment works (POTW) will have to satisfy pretreatment requirements for the POTW's. When effluents are being disposed of by deep well injection or evaporation pond, the requirements of the Safe Drinking

Water Act, the Underground Injection Control Program, and State and local pollution control agenices must be met. These regulations are specific to each receiving stream, POTW, and to the groundwater use and geology of each location in question. State water pollutant regulations may, in some cases, be more stringent than Federal water pollution regulations.

7.3.2 Solid Waste Impacts of Sodium-based Scrubbers

Sodium-based scrubbers applied to FCC units control emissions of sulfur oxides and particulate matter (catalyst fines). Control of particulate emissions from new FCC regenerators is required by an existing NSPS. Particulate matter is removed from the flue gas by the scrubber and collected in the scrubber wastewater treatment unit as a sludge. Small amounts of polyelectrolyte (from 1.5 to 4.5 kg/day for the model units) are added to the scrubber effluent during wastewater treatment to enhance removal of suspended solids.[14] Sulfur oxides emissions control does not result in any incremental changes in the amount (dry weight) of solid wastes produced over that resulting from the particulate NSPS.

7.3.3 Energy Impact of Sodium-based Scrubbers

The overall energy impact of sodium-based scrubbing systems on FCC units is negligible. However, the scrubber system would add to the electrical requirement of an FCC unit. Table 7-8 presents the annual electrical requirements for scrubber systems and for FCC units.[14-17] The scrubber system increases the total electrical consumption for FCC units using a high energy venturi by about 2 percent and approximately 20 percent for units using a jet ejector venturi scrubber. Modified/reconstructed FCC units which employ a carbon monoxide combustion furnace regeneration will require a jet ejector venturi. The jet ejectors are required to induce a draft through the venturi as sufficient line pressure is not available through the carbon monoxide boiler, which is unpressurized. Additional energy is thus consumed by the pumps which spray the scrubbing liquor through the jet ejectors as discussed in Section 4.2.2.2. The high energy venturis do not have this requirement.

Table 7-8. ANNUAL OPERATING ELECTRICITY REQUIREMENTS FOR SODIUM-BASED SCRUBBER SYSTEMS AND FCC UNITS[a]

	FCC Unit Fresh Feed Capacity (m^3/sd)	Annual Electricity Requirement for Scrubber and Wastewater Treatment System[b] (TJ)	Annual Electricity Requirement for FCC Unit[c] (TJ)	Total Annual Electricity Requirement for Scrubber System and FCC Unit (TJ)	Scrubber System Electricity Requirement As a Percent of Total
FCC Units with High Energy Venturis	2,500	1.0	46	47	2.1
	8,000	3.3	149	152	2.2
FCC Units with Jet Ejector Venturis	2,500	11	46	57	19.3
	8,000	41	149	190	21.6

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[a] Assumes that the FCC unit and scrubber each operate 357 days per year, 24 hours per day. Conversion Factors: TJ = 10^{12} Joules. KWh = 3.6×10^6 J.

[b] Reference 12. It is expected that most new and modified/reconstructed FCC units will employ high energy venturis. However, as shown in Table 7-5, two modified/reconstructed units are expected to utilize a carbon monoxide combustion furnace. These FCC units would require a jet ejector venturi with a sodium-based scrubber system. The jet ejector type venturi requires additional electricity to pump the scrubbing liquor through the jet ejectors.

[c] Calculated as an average value from References 14, 15, 16.

In assessing nationwide energy impacts for the sodium-based scrubber system, it is expected that all new units and five of the seven projected modified/reconstructed units will utilize a high energy venturi. It is anticipated that all new units will use high temperature regeneration and that conventional promoted regeneration or high temperature regeneration will be used in the case of five modified/reconstructed units. Two modified/reconstructed units are expected to use conventional-unpromoted regeneration, and hence jet ejector venturis. These units are assumed to be one 2,500 m^3/sd unit and one 8,000 m^3/sd unit charging a 1.5 weight percent sulfur feed as noted in Table 7-5.

A comparison of the scrubbing system total energy requirement to the FCC unit's energy requirement is presented in Table 7-9. The scrubbing system energy requirement for units with the high energy venturi and the jet ejector venturi is less than 1 and 2 percent of that for the total FCC unit, respectively. From Table 7-10, nationwide fifth-year energy requirements are approximately 24,000 TJ under Regulatory Alternative II and 26,900 TJ for Regulatory Alternatives III and IV.

7.3.4 Other Impacts of Sodium-based Scrubbers

7.3.4.1 Noise. An increase in noise is expected as a result of scrubber operation. Sources of noise are pumps, agitators, and fans associated with the scrubber and wastewater treatment systems. This increase in noise is not significant when compared to noise levels associated with the FCC unit and supporting equipment.

7.3.4.2 Irreversible and Irretrievable Commitment of Resources. This analysis has assumed that implementation of each regulatory alternative other than Regulatory Alternative I will require installation of sodium-based scrubbers. This will necessitate the additional use of natural resources, especially alkali. However, the commitment of these resources is expected to be small compared to national use.

7.4 ENVIRONMENTAL IMPACTS OF OTHER CONTROL TECHNOLOGIES[18]

This section discusses the environmental impacts that result from control technologies which may be used as an alternative to sodium-based

Table 7-9. ANNUAL OPERATING ENERGY REQUIREMENTS FOR SODIUM-BASED SCRUBBER SYSTEM AND FCC UNITS[a]

	FCC Unit Fresh Feed Capacity (m^3/sd)	Annual Energy Requirement for Scrubber and Wastewater Treatment System[b] (TJ)	Annual Energy Requirement for FCC Unit[c] (TJ)	Total Annual Energy Requirement for Scrubber System and FCC Unit (TJ)	Scrubber System Energy Requirement As a Percent of Total
FCC Units with high energy venturis[d]	2,500	1.2	690	691	0.17
	8,000	3.8	2,200	2,204	0.17
FCC Units with jet ejector venturis[e]	2,500	13	690	703	1.8
	8,000	42	2,200	2,242	1.9

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[a] Assumes that the FCC unit and scrubber each operate 357 days per year, 24 hours per day. Conversion Factors: TJ = 10^{12} J. kWh = 3.6×10^6 J. Btu = 1055 J.

[b] Reference 13. The components of the scrubber system energy requirements include electricity and steam.

[c] Calculated as an average value from References 14, 15, 16. Components of the FCC unit energy requirements include electricity, steam, and fuel gas.

[d] It is expected that new FCC units and some of the modified/reconstructed FCC units will use high energy venturis. The electrical requirements for these units are based on a high energy venturi system.

[e] Modified/reconstructed FCC units with carbon monoxide furnaces will require a jet ejector venturi with the sodium-based scrubber system. The jet ejector venturi requires additional energy to pump liquor through the jet ejectors.

Table 7-10. NATIONWIDE FIFTH-YEAR OPERATING ENERGY REQUIREMENTS FOR SODIUM-BASED SCRUBBING[a]

		Regulatory Alternative[b]			
		II		III and IV	
	FCC Unit Fresh Feed Capacity (m^3/sd)	Number of Affected Facilities	Nationwide Fifth-Year Energy Requirement (TJ)	Number of Affected Facilities	Nationwide Fifth-Year Energy Requirement (TJ)
New FCC Units with high energy venturis	2,500	5	3,460	6	4,150
	8,000	8	17,630	9	19,840
FCC Units with jet ejector venturis	2,500	1	703	1	703
	8,000	1	2,242	1	2,242
Total			24,000		26,900

[a] Nationwide fifth-year energy requirements are obtained by multiplying the model unit requirements from Table 7-9 by the projected growth for the fifth year given in Tables 7-4 and 7-5. It is assumed that two modified/reconstructed units will require jet ejector venturis. Conversion Factors: TJ = 10^{12} J, kWh = 3.6×10^6 J. Btu = 1055 J.

[b] Energy requirements are lower under Regulatory Alternative II because no control is required for units processing 0.3 weight percent sulfur feed (approximately 400 ppm SO_2).

scrubbers. These control technologies include: dual alkali, Wellman-Lord, citrate, and spray drying flue gas desulfurization and sulfur oxides reduction catalysts.

Nationwide impacts for each alternative control technology are determined by assuming that all projected units subject to standards of performance utilize the control technology discussed. Table 7-11 compares the nationwide environmental impacts of these alternative control technologies with that of sodium-based scrubbers.

7.4.1 Dual Alkali

The dual alkali FGD systems can be applied to most FCC units; however, a vendor has indicated that in circumstances where the flue gas sulfur oxides concentration is below 800 ppmv, a single alkali scrubber would be employed. In these cases, there is so much nonregenerable sulfate present that a dual alkali system is unjustifiable. In order to assess the nationwide impacts of the dual alkali system, it is assumed that sodium-based scrubbers would be employed for units treating low sulfur oxides flue gas concentrations. As shown in Table 7-4, this would affect the two projected model units with feed sulfur contents of 0.3 weight percent. The nationwide dual alkali impacts include sodium-based scrubbing impacts for these units.[18]

Dual alkali FGD systems use an aqueous sodium-based alkali solution to absorb sulfur oxides from the flue gases. A calcium-based alkali solution is then used to regenerate the active sodium solution. During this regeneration process, a calcium sulfite/sulfate precipitate is formed. This precipitate is removed for disposal. Sludge containing the calcium sulfite/sulfate solids is concentrated in a vacuum filter to about 50 percent solids by weight and sent to a landfill for disposal.[19] Projected fifth-year solid waste impacts are 228 Gg, 246 Gg, and 263 Gg for Alternatives II, III, and IV, respectively.[18]

Liquid wastes from dual alkali scrubbing are negligible, and water consumption is low in comparison to the sodium-based system. The fifth-year nationwide water consumption reported in Table 7-11 is 754,000 m^3 for each regulatory alternative. The nationwide energy impacts of the dual alkali system are comparable to the sodium-based system. Dual alkali scrubbing would require 94.4 TJ energy in the

Table 7-11. FIFTH-YEAR NATIONWIDE ENVIRONMENTAL IMPACTS, BY CONTROL SYSTEM AND REGULATORY ALTERNATIVE[18]

			Liquid Wastes					Energy Consumption	
Scrubber System	Regulatory Alternative	Solid Wastes (Gg)	Total Volume ($10^3 m^3$)	TDS (Gg)	SS (Mg)	COD (Mg)	Water Consumption ($10^3 m^3$)	TJ	Fuel Oil Equivalent[a] (m^3)
Sodium-Based	II	Neg.	2,180	109	87	87	4,420	91.4	2,300
	III	Neg.	2,440	122	98	98	4,960	96.4	2,420
	IV	Neg.	2,440	122	98	98	4,960	96.4	2,420
Wellman-Lord	II	Neg.	278	0.4	11,862	1,779	1,755	72.5	1,823
	III	Neg.	309	0.4	13,294	1,911	1,967	82.9	2,083
	IV	Neg.	312	0.4	13,294	2,024	1,967	92.1	2,313
Dual Alkali[b]	II	228	Negligible	NA	NA	NA	754	94.4	2,371
	III	246	263	13.1	10.5	10.5	1,290	99.4	2,497
	IV	263	263	13.1	10.5	10.5	1,290	99.4	2,497
Citrate	II	5.8	Negligible	NA	NA	NA	Negligible	268	6,740
	III	6.3	Negligible	NA	NA	NA	Negligible	301	7,560
	IV	6.8	Negligible	NA	NA	NA	Negligible	301	7,560
Spray Drying	II	75.4	Negligible	NA	NA	NA	1,050	204	5,120
	III	170	Negligible	NA	NA	NA	1,177	228	5,730
	IV	357	Negligible	NA	NA	NA	1,177	228	5,730

[a] Based on 39.8 GJ per m^3 fuel oil (6×10^6 Btu per barrel).

[b] Dual alkali impacts reported include the impacts of sodium-based scrubbers for the projected FCC units with feed-sulfur content of 0.3 weight percent (400 vppm). Below 800 vppm sulfur dioxide flue gas concentration, a single alkali scrubber is used because of the large amount of nonregenerable sodium sulfate produced. The dual alkali scrubber has negligible liquid waste. Reference 19.

[c] NA - Not applicable.

fifth year of the standard. Energy requirements are a function of FCC unit size and are not dependent on the level of sulfur oxides control.[18,19]

7.4.2 Wellman-Lord

The Wellman-Lord system utilizes a regenerable sodium sulfite bisulfite system to remove sulfur dioxide from the flue gas. A variable throat venturi scrubber serves to remove particulate matter and, in addition, cools and saturates the gas stream. Water consumption figures are indicated in Table 7-11.

Spent scrubbing liquor (sodium bisulfite) from the absorption stage is filtered to remove suspended solids and is heated in an evaporator for regeneration to sodium sulfite. A purge stream removes small quantities of sodium sulfate and sodium thiosulfate, formed during regeneration, from the absorbing solution. Liquid wastes, composed of the sulfate purge and the water purge streams, are treated in several ways. Some facilities route the purge streams to existing refinery wastewater treatment plants, some use the purge streams as raw material for other processing units (i.e., sulfuric acid dilution water), and still others ocean dump. The water purge from a Wellman-Lord installation will require minimal treatment, i.e., neutralization (it is only slightly acidic) and settling/filtration for removal of suspended solids. In many cases, simple ponding will result in deposition of most of the suspended solids (depending on specific gravity of the solids).[20]

Projected fifth-year liquid waste impacts are presented in Table 7-11. The COD, TDS, and SS of the water purge stream will depend, to a certain extent, on the COD, TDS, and SS of the water make-up to the Wellman-Lord plant. For example, if well water (untreated) containing 200 mg/l TDS and 40 mg/l COD is used as make-up to the scrubber, the water purge will contain approximately 1,500 mg/l TDS and 300 mg/l COD. In other words, there is a concentration ratio of about 7.5:1. In addition, the water purge will contain 5.0 weight percent maximum SS, which consist of solids removed from the FCCU gas, plus whatever SS were present in the make-up water, concentrated 7.5 times. The sulfate purge contains approximately 72 percent water and 28 percent sodium salts, with COD and SS levels of 42,000 mg/l and 100 mg/l, respectively.[18, 20]

7.4.3 Citrate

The citrate FGD system has negligible water and liquid waste requirements. The system does, however, produce a solid waste product, Glauber's salt (crystalline sodium-sulfate, $NaSO_4 \cdot 10\ H_2O$). Glauber's salt is produced at a rate of 67.3 kg per Mg of sulfur recovered.[21] Glauber's salt is produced in a filter cake with other minor constituents including diatomaceous earth, citrate salts, sulfur and catalyst fines as a stable landfill material.[22] Table 7-11 reports the fifth-year nationwide volume of solid waste at 5.8, 6.3, and 6.8 Gg for Alternatives II, III, and IV, respectively.[18]

The citrate system has comparably high electrical requirements. Under Regulatory Alternative II scrubbers would consume 268 TJ, and Alternatives III and IV would consume 301 TJ each.[23,24] Electricity is consumed by high horsepower pump and agitator loads required to move and mix viscous slurries.[25]

7.4.4 Spray Drying

The use of spray drying FGD would impose much less severe water and wastewater requirements upon implementation of the regulatory alternatives. Nationwide water consumption in the fifth year would amount to 1,050,000 m^3 under Alternative II and 1,177,000 m^3 under Alternatives III and IV.[18] In addition, spray drying does not produce a significant volume of liquid wastes.[26]

Solid wastes from the application of spray drying to FCC units is a filter cake which builds upon the fabric filter bags. The filter cakes consist of calcium sulfate and catalyst fines. It is assumed that the spray drying system will achieve 90 percent control of particulate emissions; however, it has never been demonstrated for FCC units. The nationwide solid waste impacts given in Table 7-11 amount to 75.4 Gg, 170 Gg, and 357 Gg for Alternatives II, III, and IV, respectively.[18,27]

7.4.5 Sulfur Oxides Reduction Catalysts

As discussed in Section 4.5.2, sulfur oxides reduction catalysts are an emerging control technology in fluid catalytic cracking. Sulfur oxides reduction catalysts are not expected to have any incremental impact upon solid or liquid wastes or energy consumption over baseline.

7.5 ENVIRONMENTAL IMPACT OF DELAYED STANDARDS

Delay in implementation of each regulatory alternative except Regulatory Alternative I would adversely impact air quality at the rate shown in Table 7-6. The annual sulfur oxides emissions reduction column represents the lost emissions reductions for each year the standard is delayed. No adverse solid, water, or energy impacts are expected from delaying regulatory action.

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*References can be located in Docket Number A-79-09 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

8.0 COST ANALYSIS

8.1 INTRODUCTION

The capital costs, annual costs, and cost effectiveness of implementing Regulatory Alternatives II through IV are estimated for each new and modified/reconstructed model FCC unit. These estimates are used to determine the economic impacts of the regulatory alternatives upon the petroleum refining industry. The economic impact analysis is presented in Chapter 9.0. No control costs are associated with Regulatory Alternative I as this is the baseline level.

As discussed in Section 6.1, this cost analysis is founded on the application of sodium-based scrubber technology to model FCC unit flue gas parameters. The capital and annual cost of treating and disposing of the scrubber waste stream to surface water is included in the scrubber system costs. A description of a sodium-based scrubbing system is provided in Section 4.2; model unit flue gas parameters are presented in Section 6.1. To ensure a common cost basis, Nelson Cost Indexes are used to adjust costs to fourth quarter 1980 dollars.[1]

Although several vendors market sulfur oxides scrubber systems that can be applied to FCC regenerators, the sodium-based scrubbers presently in use on FCC regenerators at five refineries are licensed by one vendor. The vendor provided capital and annual costs for two model units. These model FCC units have throughput capacities of 2,500 and 8,000 m^3 fresh feed/stream day and a flue gas sulfur oxides concentration of 1,400 vppm. Scaling and other factors provided by the vendor allow determination of annual scrubber costs for all other model units.[2]

A discussion of costs for other flue gas desulfurization systems and sulfur oxides reduction catalysts is presented in Section 8.2. While only the sodium-based scrubber system has been widely applied to

FCC units at present, these alternative control technologies may also be applied to FCC units upon implementation of new source performance standards for sulfur oxides. And, in Section 8.3 the costs for an electrostatic precipitator (ESP) are included in the discussion of other costs. The cost for particulate emissions control is included in the baseline costs, Regulatory Alternative I, because the existing NSPS requires particulate control. Therefore, a credit for particulate control, based on ESP costs, is applied to the total annual costs for flue gas desulfurization systems which control particulates in addition to sulfur oxides.

8.2 SODIUM-BASED FLUE GAS DESULFURIZATION COSTS

This section presents the capital and annual costs for sodium-based scrubbing and wastewater treatment systems. As discussed in Sections 8.2.1 and 8.2.2, the cost for sodium-based scrubbing applied to FCC units is dependent upon the type of venturi scrubber used. A high energy venturi scrubber would be employed by FCC units operating under high temperature regeneration (HTR) or conventional promoted regeneration. FCC units which operate with a carbon monoxide combustion furnace would utilize a jet ejector type venturi.

8.2.1 Capital and Annual Costs for Sodium-based High Energy Venturi Scrubbers

The high energy venturi relies upon line pressure from the regenerator to force flue gas through the venturi without fans. High energy venturis are expected to be used by all new FCC units and modified/reconstructed units unless the unit relies upon a boiler for carbon monoxide combustion. It is estimated that five of the seven projected modified/reconstructed units in Table 7-5 will utilize high energy venturis.

The capital cost of the sodium-based scrubber system (including wastewater treatment) is primarily a function of the regenerator flue gas flow rate and, hence, FCC throughput. It is not dependent on the inlet concentration of sulfur oxides in the flue gas.[2] Scrubber system capital costs for the 2,500 and 8,000 m^3/sd model units are presented in Table 8-1. The total capital costs are \$4.0 million and \$6.8 million, respectively.

Table 8-1. CAPITAL COST FOR SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING SYSTEM AND PURGE TREATMENT FOR MODEL UNITS[a]

	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
Total Direct Costs[b]	2.3	4.0
Indirect Costs	1.0	1.7
Total Direct and Indirect	3.3	5.7
Contingency[c]	0.7	1.1
Total Capital Cost	4.0	6.8
ESP Capital Cost Credit[d]	-0.8	-1.4

[a] Costs are reported in millions of dollars, adjusted to fourth quarter 1980, delivered to a Gulf Coast location. See Reference 2.

[b] Materials and labor.

[c] Twenty percent of total direct and indirect costs.

[d] From Table 8-19.

The regulatory alternatives, shown graphically in Figure 6-1, require sulfur oxides control efficiencies to 93 percent, depending on feedstock quality and regulatory alternative. The annual cost of using the sodium-based scrubber system to control sulfur oxides emissions is dependent on the quantity of sulfur oxides removed from the flue gas stream. For a particular regulatory alternative there is a direct relationship between the sulfur oxides concentration at the scrubber inlet and the utility costs.[2]

Only one utility cost component, alkali, varies significantly with inlet sulfur oxides concentration and regulatory alternative. The other utility costs are constant because of the particulate collection requirements of the scrubbing system. To meet the particulate NSPS, the scrubber liquid-to-gas ratio must remain constant throughout the range of expected sulfur oxides loadings and removal efficiencies. Since the regenerator flue gas flow rate is constant for a given model unit throughput, scrubber liquor recirculating pumps, waste treatment equipment, and other equipment operate at constant conditions. Thus, only alkali consumption changes with flue gas sulfur oxides variations. Alkali consumption is assumed to vary proportionally with the scrubber inlet loading[2] and with the level of sulfur oxides control required for each regulatory alternative.

The assumptions used to develop annual costs are summarized in Table 8-2. Table 8-3 provides the bases for determining annual costs. Maintenance, capital cost recovery, tax, insurance, and administrative costs are calculated by applying the appropriate capital cost from Table 8-1.

Annual costs for each model unit meeting Regulatory Alternatives II through IV are presented in Tables 8-4 through 8-9. Two annual costs are reported for each model unit since either caustic soda or soda ash may be used as the alkali. Annual sulfur oxides emission reduction and cost effectiveness are reported for each model unit and regulatory alternative. Annual emission reductions are reported in Mg/yr, and cost effectiveness is reported in $/Mg sulfur oxides removed. The higher annual cost value with caustic soda is used to calculate cost effectiveness. Because it may not be possible to scale down the scrubber control efficiencies to meet the levels of the regulatory alternatives (as little as 25 percent in some cases), a second net cost, emission reduction, and cost effectiveness is shown for "full scrubbing." Full scrubbing is defined here to mean control to 50 vppm for the low sulfur model plants, 93 percent control for the high sulfur model plants to meet regulatory alternative IV, and 90 percent control for all other cases. The costs have been revised to reflect the higher degree of caustic consumption and the emission reductions have been revised to reflect the correspondingly high reduction in SO_x emissions.

Table 8-2. ASSUMPTIONS USED TO DEVELOP ANNUAL COSTS

Assumptions

1. New FCC units utilize high temperature regeneration. Existing units utilize either conventional regeneration with carbon monoxide combustion promoters or a carbon monoxide combustion furnace to combust carbon monoxide in a controlled manner outside the regenerator vessel. Sodium-based scrubbers will utilize high energy venturis unless the unit is equipped with a carbon monoxide boiler.

2. The cost of treating the scrubber waste stream is included in the scrubber system annual costs. The scrubber purge treatment unit consists of below-ground ponding for sedimentation of the suspended solids (catalyst fines) and surface aerators in below-ground ponds to reduce the chemical oxygen demand of the purge stream to acceptable levels prior to discharge. Inland disposal using evaporative ponds is discussed in Section 8.2.3. Other systems that have no wastewater discharge are presented in Section 8.3.

3. Caustic (or soda ash) consumption is proportional to the amount of sulfur oxides removed for each regulatory alternative. All other utilities remain constant.

4. FCC unit and scrubber system operate 357 days per year (approximately 98 percent availability), based on a typical FCC unit turnaround of about 3 weeks every 3 years.

5. Solid wastes consist primarily of catalyst fines. The amount of solid waste to be disposed is calculated assuming 90 percent collection of 0.85 g particulate/Nm^3 into the scrubber.

6. The capital recovery factor (CRF) is based on a 10 percent interest rate and an expected service life of 15 years for the scrubber and purge treatment system.[3]

Table 8-3. BASES FOR DETERMINING ANNUAL COSTS

Direct Operating Costs	
Labor	\$14.35/hour[a]
Maintenance (includes materials, manning, and overhead)	1.5 percent of total capital cost[b]
Utilities	
Electricity	\$0.0652/kWh[c]
Water	\$0.0625/m^3[d]
Compressed Air	\$0.706/1,000 m^3[d]
Caustic Soda (Soda Ash)	\$220/Mg[e] (\$100/Mg)[f]
Steam	\$11.09/1,000 kg[d]
Polyelectrolyte	\$8.25/kg[g]
Waste Disposal	\$16.50/Mg[c]
Indirect Operating Costs	
Tax, Insurance, and Administration	4 percent of total capital cost[d]
Capital Recovery Factor	13.15 percent of total capital cost[d]

[a] Includes 40 percent overhead. Reference 3.

[b] See Reference 2.

[c] Cost from Reference 4, updated to September 1980. Reference 3.

[d] See Reference 4.

[e] Liquid caustic soda, 100 percent. F.O.B. Gulf Coast. Reference 5.

[f] Bulk soda ash, light, 99 percent. F.O.B. Wyoming. Reference 6, 7.

[g] Polymer 3300, an anionic polyacrilomide settling agent. Fifty pound bags, F.O.B. Dallas, Texas. Reference 8.

Table 8-4. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE - CASE 1[a]

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II[c]	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor		44.0	44.0
Maintenance		60	60
Utilities			
Electricity		18.4	18.4
Water		8.4	8.4
Compressed Air		0.3	0.3
Caustic Soda (Soda Ash)		36.8 (22.5)	73.6 (45.1)
Steam		0.9	0.9
Polyelectrolyte		4.0	4.0
Waste Disposal		5.8	5.8
Indirect Operating Costs			
Tax, Insurance, and Administration		160	160
Capital Recovery Cost		526	526
Total Annual Cost			
With Caustic Soda (Soda Ash)	0	860 (850)	900 (870)
ESP Credit		-200	-200
NET ANNUAL COST			
With Caustic Soda (Soda Ash)		660 (650)	700 (670)
Emission Reduction (Mg SO_x removed/yr)	0	130	260
Cost Effectiveness[d] ($/Mg SO_x removed)		5,080	2,690
FULL SCRUBBING[e]			
Net Annual Cost With Caustic Soda		760	760
Emission Reduction (Mg SO_x removed/yr)	0	450	450
Cost Effectiveness ($/Mg SO_x removed)		1,690	1,690

[a] Based on data available in Reference 2. Case 1: 2,500 m^3/sd model unit, 0.3 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] No controls necessary to meet this regulatory alternative.

[d] Based on net annual cost with caustic soda.

[e] Based on control to 50 vppm with caustic soda. Reference 45.

Table 8-5. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE[a] - CASE 2

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor	44.0	44.0	44.0
Maintenance	60	60	60
Utilities			
Electricity	18.4	18.4	18.4
Water	8.4	8.4	8.4
Compressed Air	0.3	0.3	0.3
Caustic Soda	381	418	456
(Soda Ash)	(234)	(256)	(279)
Steam	0.9	0.9	0.9
Polyelectrolyte	4.0	4.0	4.0
Waste Disposal	5.8	5.8	5.8
Indirect Operating Costs			
Tax, Insurance, and Administration	160	160	160
Capital Recovery Cost	526	526	526
Total Annual Cost			
With Caustic Soda	1,210	1,240	1,280
(Soda Ash)	(1,060)	(1,080)	(1,100)
ESP Credit	-200	-200	-200
NET ANNUAL COST			
With Caustic Soda	1,010	1,040	1,080
(Soda Ash)	(860)	(880)	(900)
Emission Reduction (Mg SO_x removed/yr)	1,340	1,470	1,600
Cost Effectiveness[c] ($/Mg SO_x removed)	760	710	680
FULL SCRUBBING[d]			
Net Annual Cost With Caustic Soda	1,100	1,100	1,100
Emission Reduction (Mg SO_x removed/yr)	1,670	1,670	1,670
Cost Effectiveness ($/Mg SO_x removed)	660	660	660

[a] Based on data available in Reference 2. Case 2: 2,500 m^3/sd model unit, 1.5 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] Based on net annual cost with caustic soda.

[d] Based on 90 percent control with caustic soda. Reference 45.

Table 8-6. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE[a] - CASE 3

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor	44.0	44.0	44.0
Maintenance	60	60	60
Utilities			
Electricity	18.4	18.4	18.4
Water	8.4	8.4	8.4
Compressed Air	0.3	0.3	0.3
Caustic Soda (Soda Ash)	846 (519)	884 (542)	920 (564)
Steam	0.9	0.9	0.9
Polyelectrolyte	4.0	4.0	4.0
Waste Disposal	5.8	5.8	5.8
Indirect Operating Costs			
Tax, Insurance, and Administration	160	160	160
Capital Recovery Cost	526	526	526
Total Annual Cost			
With Caustic Soda (Soda Ash)	1,670 (1,340)	1,710 (1,370)	1,740 (1,390)
ESP Credit	-200	-200	-200
NET ANNUAL COST			
With Caustic Soda (Soda Ash)	1,470 (1,140)	1,510 (1,170)	1,540 (1,190)
Emission Reduction (Mg SO_x removed/yr)	2,970	3,100	3,230
Cost Effectiveness[c] ($/Mg SO_x removed)	490	490	480
FULL SCRUBBING[d]			
Net Annual Cost			
With Caustic Soda	1,520	1,520	1,540
Emission Reduction (Mg SO_x removed/yr)	3,130	3,130	3,230
Cost Effectiveness ($/Mg SO_x removed)	490	490	480

[a] Based on data available in Reference 2. Case 3: 2,500 m^3/sd model unit, 3.5 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] Based on net annual cost with caustic soda.

[d] Based on 90 percent control for alternatives II and III and 93 percent control for alternative IV with caustic soda. Reference 45.

Table 8-7. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE[a] - CASE 4

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II[c]	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor		44.0	44.0
Maintenance		102	102
Utilities			
Electricity		58.7	58.7
Water		25.1	25.1
Compressed Air		0.3	0.3
Caustic Soda (Soda Ash)		118 (73)	236 (146)
Steam		2.6	2.6
Polyelectrolyte		12.0	12.0
Waste Disposal		18.6	18.6
Indirect Operating Costs			
Tax, Insurance, and Administration		272	272
Capital Recovery Cost		894	894
Total Annual Cost			
With Caustic Soda (Soda Ash)	0	1,550 (1,500)	1,670 (1,580)
ESP Credit		-330	-330
NET ANNUAL COST			
With Caustic Soda (Soda Ash)		1,220 (1,170)	1,340 (1,250)
Emission Reduction (Mg SO_x removed/yr)	0	410	830
Cost Effectiveness[d] (\$/Mg SO_x removed)		2,980	1,610
FULL SCRUBBING[e]			
Net Annual Cost With Caustic Soda		1,510	1,510
Emission Reduction (Mg SO_x removed/yr)	0	1,440	1,440
Cost Effectiveness (\$/Mg SO_x removed)		1,050	1,050

[a] Based on data available in Reference 2. Case 4: 8,000 m^3/sd model unit, 0.3 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] No controls necessary to meet this regulatory alternative.

[d] Based on net annual cost with caustic soda.

[e] Based on control to 50 vppm with caustic soda. Reference 45.

Table 8-8. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE[a] - CASE 5

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor	44.0	44.0	44.0
Maintenance	102	102	102
Utilities			
Electricity	58.7	58.7	58.7
Water	25.1	25.1	25.1
Compressed Air	0.3	0.3	0.3
Caustic Soda (Soda Ash)	1,220 (755)	1,340 (829)	1,460 (902)
Steam	2.6	2.6	2.6
Polyelectrolyte	12.0	12.0	12.0
Waste Disposal	18.6	18.6	18.6
Indirect Operating Costs			
Tax, Insurance, and Administration	272	272	272
Capital Recovery Cost	894	894	894
Total Annual Cost			
With Caustic Soda (Soda Ash)	2,650 (2,180)	2,770 (2,260)	2,890 (2,331)
ESP Credit	-330	-330	-330
NET ANNUAL COST			
With Caustic Soda (Soda Ash)	2,320 (1,850)	2,440 (1,928)	2,560 (2,000)
Emission Reduction (Mg SO_x removed/yr)	4,290	4,710	5,120
Cost Effectiveness[c] ($/Mg SO_x removed)	540	518	500
FULL SCRUBBING[d]			
Net Annual Cost			
With Caustic Soda	2,630	2,630	2,630
Emission Reduction (Mg SO_x removed/yr)	5,350	5,350	5,350
Cost Effectiveness ($/Mg SO_x removed)	490	490	490

[a] Based on data available in Reference 2. Case 5: 8,000 m^3/sd model unit, 1.5 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] Based on net annual cost with caustic soda.

[d] Based on 90 percent control with caustic soda. Reference 45.

Table 8-9. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE[a] - CASE 6

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor	44.0	44.0	44.0
Maintenance	102	102	102
Utilities			
Electricity	58.7	58.7	58.7
Water	25.1	25.1	25.1
Compressed Air	0.3	0.3	0.3
Caustic Soda	2,710	2,830	2,950
(Soda Ash)	(1,675)	(1,750)	(1,820)
Steam	2.6	2.6	2.6
Polyelectrolyte	12.0	12.0	12.0
Waste Disposal	18.6	18.6	18.6
Indirect Operating Costs			
Tax, Insurance, and Administration	272	272	272
Capital Recovery Cost	894	894	894
Total Annual Cost			
With Caustic Soda	4,140	4,260	4,370
(Soda Ash)	(3,100)	(3,180)	(3,250)
ESP Credit	-330	-330	-330
NET ANNUAL COST			
With Caustic Soda	3,810	3,930	4,040
(Soda Ash)	(2,770)	(2,850)	(2,920)
Emission Reduction (Mg SO_x removed/yr)	9,500	9,910	10,300
Cost Effectiveness[c] ($/Mg SO_x removed)	400	400	390
FULL SCRUBBING[d]			
Net Annual Cost With Caustic Soda	3,950	3,950	4,040
Emission Reduction (Mg SO_x removed/yr)	9,990	9,990	10,300
Cost Effectiveness ($/Mg SO_x removed)	400	400	390

[a] Based on data available in Reference 2. Case 6: 8,000 m^3/sd model unit, 3.5 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] Based on net annual cost with caustic soda.

[d] Based on 90 percent control for alternatives II and III and 93 percent for alternative IV with caustic soda. Reference 45.

From Tables 8-4 through 8-9, net annual costs for model units range from about \$1.1 million for a 2,500 m^3/sd unit processing 0.3 weight percent sulfur and meeting Regulatory Alternative III to \$4.0 million for an 8,000 m^3/sd unit processing 3.5 weight percent sulfur and meeting Regulatory Alternative IV. For these two units, annual sulfur oxides emission reductions range from 130 to 10,300 Mg and cost effectiveness ranges from \$5,080 to \$390/Mg sulfur oxides removed, respectively.

8.2.2 Capital and Annual Costs for Sodium-based Jet Ejector Venturi Scrubbers

Jet ejector venturis would be utilized with sodium-based scrubbing for FCC units equipped with a carbon monoxide combustion furnace. Under these conditions, additional energy is required to move the regenerator flue gas through the scrubber and out the stack. A jet ejector-type venturi serves this purpose.

It is estimated that two of the modified/reconstructed units projected in Table 7-5 will employ a jet-ejector type venturi. And, in order to assess nationwide impacts of sodium-based scrubbing, it is assumed that these two units are characterized by one small and one large FCC model unit, each charging a 1.5 weight percent sulfur feedstock.

The capital costs for sodium-based scrubbing with a jet-ejector type venturi are higher than that of high energy venturi scrubbers. The higher costs are attributed to the additional piping, pumps, and spray nozzles that comprise the jet ejector scrubber system as discussed in Section 4.2.2.2. From Table 8-10, the total capital costs for jet ejector sodium-based scrubbing systems applied to 2,500 m^3/sd and 8,000 m^3/sd model units are \$5.5 million and \$9.6 million, respectively.

Annual costs for sodium-based scrubbing are also higher with jet ejector venturis as compared to the high energy venturis. The higher cost is largely due to the additional electrical requirement of jet ejector venturi scrubbers as discussed in Section 7.3.3. Tables 8-11 and 8-12 itemize the annual costs for a 2,500 m^3/sd unit and 8,000 m^3/sd unit based upon jet ejector venturi scrubbers. The cost effectiveness for these units ranges from \$1,120/Mg sulfur oxides removed for a small model unit Regulatory Alternative II to \$740/Mg sulfur oxides removed for a large model unit under Regulatory Alternative III. As in Tables 8-4 through 8-9, a separate cost and emission reduction is shown for a 90 percent, "full scrubbing" case.

Table 8-10. CAPITAL COST FOR SODIUM-BASED JET EJECTOR VENTURI SCRUBBING SYSTEM AND PURGE TREATMENT FOR MODEL UNITS[a]

	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
Total Direct Costs[b]	3.3	5.6
Indirect Costs	1.3	2.4
Total Direct and Indirect	4.6	8.0
Contingency[c]	0.9	1.6
Total Capital Cost	5.5	9.6
ESP Capital Cost Credit[d]	-0.8	-1.4

[a] Costs are reported in millions of dollars, adjusted to fourth quarter 1980, delivered to a Gulf Coast location. See Reference 2.

[b] Materials and labor.

[c] Twenty percent of total direct and indirect costs.

[d] From Table 8-19.

Table 8-11. ANNUAL COST OF SODIUM-BASED JET EJECTOR VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE[a] - CASE 7

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor	44.0	44.0	44.0
Maintenance	82.5	82.5	82.5
Utilities			
Electricity	235	235	235
Water	8.4	8.4	8.4
Compressed Air	0.3	0.3	0.3
Caustic Soda (Soda Ash)	381 (234)	418 (256)	456 (279)
Steam	0.9	0.9	0.9
Polyelectrolyte	4.0	4.0	4.0
Waste Disposal	5.8	5.8	5.8
Indirect Operating Costs			
Tax, Insurance, and Administration	220	220	220
Capital Recovery Cost	723	723	723
Total Annual Cost			
With Caustic Soda (Soda Ash)	1,700 (1,560)	1,740 (1,580)	1,780 (1,600)
ESP Credit	-200	-200	-200
NET ANNUAL COST			
With Caustic Soda (Soda Ash)	1,500 (1,360)	1,540 (1,380)	1,580 (1,400)
Emission Reduction (Mg SO_x removed/yr)	1,340	1,470	1,600
Cost Effectiveness[c] ($/Mg SO_x removed)	1,120	1,050	990
FULL SCRUBBING[d]			
Net Annual Cost With Caustic Soda	1,600	1,600	1,600
Emission Reduction (Mg SO_x removed/yr)	1,670	1,670	1,670
Cost Effectiveness ($/Mg SO_x removed)	960	960	960

[a] Based on data available in Reference 2. Case 7: 2,500 m^3/sd model unit, 1.5 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] Based on net annual cost with caustic soda.

[d] Based on 90 percent control with caustic soda. Reference 45.

Table 8-12. ANNUAL COST OF SODIUM-BASED JET EJECTOR VENTURI SCRUBBING FOR MODEL UNITS BY REGULATORY ALTERNATIVE[a] - CASE 8

	Annual Cost, in thousands of dollars[b]		
	Reg. Alt. II	Reg. Alt. III	Reg. Alt. IV
Direct Operating Costs			
Labor	44.0	44.0	44.0
Maintenance	144	144	144
Utilities			
Electricity	754	754	754
Water	25.1	25.1	25.1
Compressed Air	0.3	0.3	0.3
Caustic Soda	1,220	1,340	1,460
(Soda Ash)	(755)	(829)	(902)
Steam	2.6	2.6	2.6
Polyelectrolyte	12.0	12.0	12.0
Waste Disposal	18.6	18.6	18.6
Indirect Operating Costs			
Tax, Insurance, and Administration	384	384	384
Capital Recovery Cost	1,261	1,261	1,261
Total Annual Cost			
With Caustic Soda	3,870	3,990	4,110
(Soda Ash)	(3,400)	(3,480)	(3,550)
ESP Credit	-330	-330	-330
NET ANNUAL COST			
With Caustic Soda	3,540	3,660	3,780
(Soda Ash)	(3,070)	(3,150)	(3,220)
Emission Reduction (Mg SO_x removed/yr)	4,290	4,710	5,120
Cost Effectiveness[c] ($/Mg SO_x removed)	830	780	740
FULL SCRUBBING[d]			
Net Annual Cost			
With Caustic Soda	3,850	3,850	3,850
Emission Reduction (Mg SO_x removed/yr)	5,350	5,350	5,350
Cost Effectiveness ($/Mg SO_x removed)	720	720	720

[a] Based on data available in Reference 2. Case 8: 8,000 m^3/sd model unit, 1.5 weight percent sulfur feedstock.

[b] Numbers may not add to totals due to rounding. Fourth quarter 1980 dollars.

[c] Based on net annual cost with caustic soda.

[d] Based on 90 percent control with caustic soda. Reference 45.

8.2.3 Water and Solid Waste Cost Impacts

The purge stream from the sodium-based scrubber is treated prior to discharge to coastal waters. The wastewater treatment system costs are included with the scrubber system costs in Tables 8-1 and 8-4 through 8-12. The treatment system represents approximately 25 percent of the total direct cost reported in Tables 8-1 and 8-10, and 30 percent of the annual cost of utilities reported in Tables 8-4 through 8-9 and 8-11 and 8-12.

The five refineries with sodium scrubbers in place for sulfur oxides control are in or near coastal locations and discharge the treated scrubber wastewater to large rivers or coastal waters. Refiners in inland locations considering the sodium-based scrubber for FCC sulfur oxides control may not be able to discharge the treated scrubber wastestream to inland bodies of water due to water quality considerations and discharge permits. For these inland refiners, vapor compression distillation, multistaged flash evaporation, evaporation ponds, reverse osmosis, or deep well injection may be viable approaches for disposal of the scrubber effluent.[9] Of the 102 sodium scrubber systems currently in use on industrial boilers, about 80 use evaporation ponds and 10 use centralized water treating systems. The remainder use varied approaches ranging from discharge to city sewers to deep well injection.

The use of sodium-based scrubbers, however, may not be feasible for some inland FCC units. One limiting factor is the availability of sufficient water to operate the scrubbing system. A second limiting factor is the ability to dispose wastewater produced by this scrubber system. Based on industrial boiler use, evaporation ponds would be the likely method for waste disposal. However, the use of evaporation ponds is limited to certain geographic areas of the country where annual evaporation rates exceed the annual rainfall.[10] An alternative to evaporation ponds is to dilute the wastewater and discharge to surface waters (providing the necessary water resources exist).

Due to the problems associated with sodium-based scrubbers mentioned above, it is anticipated that some refiners will opt to employ control technologies with less severe water and wastewater discharge requirements.

These control systems are discussed in Chapter 4, and their environmental impacts are presented in Section 7.4. Costs for these alternative control technologies are presented in Section 8.3.11

No additional solid waste cost impacts are anticipated through addition of sodium-based scrubbers for control of sulfur oxides.

8.2.4 Nationwide Cost Impacts

The projected nationwide cost impacts for sodium-based scrubbing are presented in Table 8-13 along with the costs for the other control technologies discussed in Section 8.3. The nationwide cost impacts assume that all FCC units subject to standards of performance will employ the same control technology. These projections are calculated using anticipated FCC unit construction, modification, and reconstruction from Tables 7-4 and 7-5 and the capital and annual costs for each model unit.

The cumulative 5-year capital costs for sodium-based scrubbing are $72.1 million for Regulatory Alternative II and $80.7 million for Regulatory Alternatives III and IV. Annual costs in the fifth year of the standard, 1986, are based on scrubbing with caustic soda. Annual costs in the fifth year of the standard are $32.1 million, $35.3 million, and $36.7 million for Regulatory Alternatives II, III, and IV, respectively.

8.3 OTHER CONTROL TECHNOLOGY COSTS

The following sections present costs for alternative control technologies which may be applied to FCC units to control sulfur oxides emissions to the level of the regulatory alternatives. While these control technologies are not presently commercially applied to FCC regenerators, it is likely that these could be considered as necessary for specific applications. These control technologies, discussed in Chapter 4.0, are analyzed on similar cost bases as the sodium-based scrubber in order to compare the costs of the different systems. The costs are updated to fourth quarter 1981 dollars using Nelson Cost Indexes and many assumptions used in the sodium-based scrubber are used in the other systems. For example, all capital costs include a 20 percent contingency, and the annual costs assume a 15-year life for determining the capital recovery costs for each system. The same unit costs for utilities and operating labor and materials are also used in each system.

Table 8-13. COMPARISON OF FIFTH-YEAR NATIONWIDE SCRUBBER SYSTEM COSTS
(Thousands of Fourth Quarter 1980 Dollars)

Nationwide Costs[a,b]	Regulatory Alternative		
	II	III	IV
Five-Year Capital Cost			
Sodium Based	72,100	80,700	80,700
Wellman-Lord	106,000	116,000	119,000
Dual Alkali	35,700	45,700	47,200
Citrate	56,100	60,500	60,500
Spray Drying	53,200	59,700	59,700
Fifth-Year Annual Cost			
Sodium Based	32,100	35,300	36,700
Sodium Based (full scrubbing)	35,000	37,300	37,500
Wellman-Lord	28,200	31,200	32,900
Dual Alkali	16,400	19,100	20,100
Citrate	25,900	18,100	5,430
Spray Drying	15,900	20,100	32,600

[a] The costs reported assume that all new and modified/reconstructed FCC units will employ the scrubbing system costed.

[b] The nationwide costs for each scrubber system are calculated by multiplying the costs per model unit by the projected number of model units subject to standards of performance under each regulatory alternative. A schedule of model units subject to the regulatory alternatives is provided in Tables 7-4 and 7-5. Reference 11.

An itemized cost table for each control technology is presented for a 2,500 m^3/sd and 8,000 m^3/sd model unit assuming a 1.5 percent sulfur feedstock subject to Regulatory Alternative III. This scenario corresponds to a 1,400 vppm sulfur dioxide inlet concentration and control to 300 vppm. Table 8-13 presents a comparison of the nationwide control costs based on the different control technologies and regulatory alternatives. The nationwide costs report the cumulative 5-year capital cost and the fifth year annual cost for each control technology. The nationwide costs assume that all affected facilities employ the same control technology. This analysis provides a basis for comparing the system costs; however, it is unlikely that any one control system will be relied upon for all FCC units. In addition, the sodium-based system costs are from actual FCC regenerator application experience. Other systems will likely incur increased costs to increase their on-line reliability to match that of the FCC unit.

8.3.1 Dual Alkali Flue Gas Desulfurization

The costs of applying dual alkali scrubbers to FCC units are presented in this section. Cost information was obtained from a dual alkali vendor.[12,13] The itemized capital and annual costs for the model units are given in Table 8-14 for a 1.5 weight percent sulfur feedstock. Because the dual alkali system employs a packed tower absorber, the system does not afford the secondary advantage of particulate control as was the case for sodium-based scrubbers.[16] Therefore, the annual costs of an electrostatic precipitator are not credited to the dual alkali system costs.

According to the dual alkali vendor, the dual alkali system is not feasible for flue gas concentrations of less than 800 vppm sulfur dioxide. Low scrubber sulfur dioxide inlet concentrations would result in a high level of nonregenerable sulfate present in the scrubbing liquor.[15] In these applications, a single alkali system would be applied. Hence, in order to determine nationwide cost impacts, sodium-based scrubbing costs as discussed in Section 8.2 are used for the projected units processing feedstocks with low sulfur content (0.3 weight percent sulfur, corresponds to a 400 vppm inlet sulfur dioxide level). Nationwide costs are reported in Table 8-13.[11]

Table 8-14. DUAL ALKALI SCRUBBING SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III
(Costs Reported in Thousands of Dollars)[a]

	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
CAPITAL COSTS[b]		
Equipment	827	1,504
Construction	451	818
Engineering	226	404
Total Capital Costs[c]	1,504	2,726
ANNUAL COST		
Direct Operating Costs		
Operating Labor[d]	31	61
Maintenance[e]	23	41
Utilities		
Soda Ash[f]	8	27
Lime[g]	80	248
Electricity[h]	50	157
Water[i]	1	4
Waste Disposal[j]	96	301
Indirect Operating Costs		
Tax, Insurance, and Administration[k]	60	109
Capital Recovery Cost[l]	198	358
TOTAL ANNUAL COSTS	547	1,305
EMISSION REDUCTION (Mg SO_2 removed/ year	1,470	4,710
COST EFFECTIVENESS ($/Mg of SO_2 removed)	372	277

Footnotes are on the next page.

Table 8-14. DUAL ALKALI SCRUBBING SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III (Concluded)

[a] Nelson cost indexes were used to adjust costs to fourth quarter 1980 dollars.

[b] References 12, 13.

[c] The capital costs include 20 percent contingency. Reference 14.

[d] Operating labor cost based on $14.35 per man-hour. Operator labor requirements are 6 man-hours/day for the small model plant; 12 man-hours per day for the large model plant. Reference 15.

[e] Maintenance costs are calculated as 1.5 percent of the total capital costs. Reference 4.

[f] Soda ash costs are based on use of 100 percent soda ash at $100/Mg. Soda ash requirement for the small unit is 9.07 kg/hour; for the large model unit, 31.8 kg/hour. References 6, 7, 15.

[g] Lime costs are based on $62/Mg lime. Lime requirement for the small unit is 149 kg/hr; and 467 kg/hr for the large model unit. Reference 15.

[h] Electricity costs based on $0.0652/kWh. Electricity requirements are 90 kW for the small model unit; 280 kW for the large model unit. References 4, 15.

[i] Water costs are based on $0.0625/m^3. Water requirements for the small model unit are 0.0464 m^3/min, for the large model unit, 0.132 m^3/min. References 4, 15.

[j] Based on waste disposal cost of $16.50/Mg. Waste disposal requirements for the small model unit are 5,831 Mg/year; for the large model unit, 18,271 Mg/year. References 4, 15.

[k] Calculated as 4 percent of the total capital cost. Reference 4.

[l] Cost is based on a life of 15 years and 10 percent interest. Capital recovery cost is calculated by 0.1315 x total capital cost. The vendor indicates a service life ranging from 15 to 25 years. References 4, 15.

8.3.2 Wellman-Lord

Capital and annual costs for the Wellman-Lord flue gas desulfurization system were provided by a vendor for the FCC unit parameters given in Table 6-2.[18-20] Both capital and annual costs for this system are dependent upon flue gas air flow rates and the degree of sulfur oxides removal required. As discussed in Section 4.2.6.1, the Wellman-Lord process consists of two stages. The capital cost for the absorber stage is dependent upon air flow and the regenerator upon sulfur oxides removal.[18] Itemized costs for the Wellman-Lord system as applied to FCC units is presented in Table 8-15. These costs are based on a 1.5 weight percent sulfur feedstock and control to Regulatory Alternative III, 400 vppm SO_2.

The Wellman-Lord vendor indicated that the sulfur dioxide recovered would be further processed at an existing Claus plant for sulfuric acid or elemental sulfur. Using a mass ratio of 2:1 sulfur dioxide to elemental sulfur, a product credit was applied to the total annual costs based on elemental molten sulfur. Credit for particulate control is also included in the net annual costs; however, it has not yet been determined whether the venturi scrubber will satisfy the particulate emissions limit because the system has not been applied to commercial FCC units.

8.3.3 Citrate FGD System Costs

The capital and annual costs for a citrate flue gas desulfurization system have been scaled according to the model unit parameters by applying factors provided by a citrate vendor.[11] The capital costs for citrate systems are dependent upon the flue gas flow rate and the flue gas sulfur dioxide concentration for the FCC unit application. Operating costs for a citrate system are also dependent upon the amount of sulfur oxides reduction. For example, the citrate system requires both citric acid and soda ash in amounts which vary with sulfur dioxide removal from the inlet flue gas.

The citrate system recovers elemental sulfur, and hence, this recovered product is credited to the total annual costs. In addition, the annual costs of an electrostatic precipitator are credited to the citrate annual costs because the citrate system venturi scrubber would provide particulate control. However, vendors caution that it remains

Table 8-15. WELLMAN-LORD SO_2 RECOVERY SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III

(Costs Reported in Thousands of Dollars)[a]

	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
TOTAL CAPITAL COSTS[b,c]	5,000	8,200
ANNUAL COSTS[d]		
Direct Operating Costs		
Operating Labor[e]	200	328
Maintenance Labor and Supplies[f]	175	287
Utilities		
Electricity[g]	65	93
Water[h]	3	10
Soda Ash[i]	30	96
Steam[j]	203	651
Indirect Operating Costs		
Tax, Insurance, and Administration[k]	200	328
Capital Recovery Cost[l]	658	1,078
TOTAL ANNUAL COSTS	1,534	2,871
PRODUCT RECOVERY CREDIT[m]	-102	-327
ESP CREDIT[n]	-200	-330
NET ANNUAL COST	1,232	2,214
EMISSION REDUCTION (Mg SO_2 removed /year)[o]	1,470	4,710
COST EFFECTIVENESS ($/Mg of SO_2 removed)	838	470

Footnotes are on the next page.

Table 8-15. WELLMAN-LORD SO_2 RECOVERY SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III (Continued)

[a] Nelson cost indexes were used to adjust costs to fourth quarter 1980 dollars except as noted.

[b] Total capital costs include 20 percent contingency. References 17, 19.

[c] Costs supplied relate to a gas flow of 3030 scmm (8,500 m^3/sd unit). For other gas flows, costs were adjusted according to information provided by vendor. Reference 18.

[d] Annual costs are determined based on 357 operating days per year.

[e] Based on 4 percent of total capital cost. Reference 21.

[f] Based on 3.5 percent of total capital cost. Reference 21.

[g] Based on small unit electrical requirement of 115.7 kW, large unit 166 kW and electricity cost of $0.0652/kWh. References 4, 18, 20.

[h] Water requirement is the net make-up to the scrubber. For the small unit, this is 0.098 m^3/min, for the large unit 0.314 m^3/min. Water cost is $0.0625/$m^3$. References 4, 18, 20.

[i] Soda ash requirement for the large model unit is 0.112 Mg/hr. Requirements for small model unit are scaled according to respective air flow rates. Soda ash cost is $100/Mg for 100 percent soda ash. References 4, 18, 20.

[j] Steam requirements are a function of the quantity of sulfur dioxide stripped from the evaporator flue gas and were supplied for the large unit (3030 scmm). Stream requirements for the small unit (950 scmm) may be determined as the product of the large unit steam requirements and the ratio of the quantity of sulfur dioxide removed relative to the large unit. Steam cost is $11.09/Mg. References 4, 18, 20.

[k] Tax, insurance, and administration is based on 4 percent of total capital cost. Reference 4.

[l] Based on 15-year expected service life and 10 percent interest rate. The capital recovery cost is calculated as 0.1315 x total capital cost. Reference 4.

Table 8-15. WELLMAN-LORD SO_2 RECOVERY SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III (Concluded)

[m] Product recovery credit is based on the annual reductions in sulfur dioxide emissions (Mg/yr) from the baseline case and a product recovery credit of $138.80 per Mg of elemental molten sulfur. Reference 22.

[n] The annual costs for an electrostatic precipitator (ESP) are credited because the system includes a variable throat venturi for flue gas saturation and particulate control. ESP costs are given in Table 8-23. Reference 17.

[o] Calculated from scrubber inlet SO_2 concentration of 1,400 vppm and 92 percent removal efficiency. Model unit air flow rates are 945 scmm for the small model unit and 3030 scmm for the large model unit.

unproven whether the venturi will provide adequate particulate control for compliance with the existing FCC unit regenerator NSPS.[29] Itemized capital and annual costs are reported in Table 8-16.

8.3.4 Spray Drying

Capital and annual costs for spray drying are given in Table 8-17 for model units on a comparable basis as the sodium-based scrubber costs. Spray drying costs are primarily a function of regenerator flue gas air flow rates. However, annual costs for this scrubber system are also determined by the amount of sulfur oxides reduction required. The costs for waste disposal, electricity, and pebble lime vary with the level of control.[30] The annual costs for an electrostatic precipitator are credited to the spray drying costs because the system controls particulate emissions in addition to sulfur dioxide emissions.[33]

8.3.5 Sulfur Oxides Reduction Catalysts Costs

The use of sulfur oxides reduction catalysts as a sulfur oxides emission control technique has thus far been confined to pilot tests and a few commercial tests; hence, the available cost information is limited. Two commercial scale test demonstrations of this control technology from two 3,500 m^3/sd FCC units each processing approximately 1 weight percent feed sulfur incurred a \$900/Mg incremental cost for sulfur oxides emission reduction.[35] The operating cost for the control additive in these tests was reported to be about \$1,400/day or approximately \$0.40/m^3 of fresh feed; catalyst cost is \$1,800/Mg as loaded.[35] Sulfur oxides reduction catalyst costs of \$0.30 to \$0.60/m^3 of fresh feed have been reported.[34,36] Fifth-year nationwide annual costs for the catalyst technology can be determined using anticipated FCC unit construction and reconstruction from Tables 7-4 and 7-5 and the catalyst cost figures from above. The fifth-year nationwide annual costs of Regulatory Alternatives II through IV calculated this way are \$10 to \$20 million, assuming the catalyst technology is applicable to all model units for each of these alternatives. No capital costs are anticipated for the catalyst technology. The cost of sulfur oxides reduction catalysts per amount of sulfur oxides removed can be calculated by dividing the fifth-year nationwide costs by the emissions reductions in the fifth year, as reported in Table 7-6. Costs determined this way are approximately \$200 to \$400/Mg sulfur oxides removed.

Table 8-16. CITRATE FGD SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III

(Costs Reported in Thousands of Dollars)[a]

	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
CAPITAL COSTS		
Direct Costs[b]	1,720	2,310
Indirect Costs[c]	616	827
Contingency[d]	584	784
TOTAL CAPITAL COSTS[e]	2,920	3,920
ANNUAL COSTS		
Direct Operating Costs		
Operating Labor[f]	260	260
General Maintenance[g]	149	149
Operating Materials[h]	14.3	45.0
Utilities		
Electricity[i]	186	415
Water[j]	Negligible	Negligible
Steam[k]	349	781
Waste Disposal[l]	2.4	7.5
Indirect Operating Costs		
Tax, Insurance, and Administration[m]	117	157
Capital Recovery Cost[n]	384	515
TOTAL ANNUALIZED COSTS	1,460	3,330
PRODUCT RECOVERY CREDIT[o]	-298	-940
ESP CREDIT[p]	-200	-330
NET ANNUAL COST	962	1,060
EMISSION REDUCTION ($Mg\ SO_2$ removed/year)	1,470	4,710
COST EFFECTIVENESS ($/Mg of SO_2 removed)	654	225

Footnotes are on the next page.

Table 8-16. CITRATE FGD SYSTEM COSTS
BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY
ALTERNATIVE III (continued)

[a] Nelson cost indexes were used to adjust costs to fourth quarter 1980 dollars except as noted.

[b] Based on 2.18 x major equipment cost. Major equipment costs were calculated based on a citrate installation which incurred a major equipment cost of $1.3 million (January 1, 1979, dollars). Major equipment costs for citrate FGD were adjusted using the following equation:

Major Equipment Cost =

$$\$1.3 \times 0.45 \times \frac{a}{4{,}800\ \text{scmm}}^{.7} + \$1.3 \times 0.55 \times \frac{b}{2500\ \text{ppm}}^{.7} \times 1.177$$

Where: a = design flue gas flow rate of citrate system being costed, scmm

b = flue gas SO_2 concentration of system being costed, ppm

1.177 = escalation factor to adjust to fourth quarter 1980 dollars. References 4, 23, 24.

[c] Based on 0.78 x the major equipment cost. The indirect costs include engineering costs as 14 percent of the total capital costs. Reference 4.

[d] Based on 20 percent of total capital cost. Reference 4.

[e] Represents 3.7 x major equipment costs. References 4, 23, 24.

[f] Model unit labor hour requirement is 17,136 man-hours per year for operators and 1,017 man-hours per year for supervisors. Labor cost is $14.35 per man-hour. References 25, 26.

[g] Based on labor requirement of 5,200 man-hours per year, $14.35 per man-hour, and material as 100 percent of maintenance labor. Reference 4, 25.

[h] Operating materials include citric acid and soda ash. Small model unit requires 5.1 Mg/yr of citric acid and 61.8 Mg/yr of soda ash. Large model unit requires 16.3 Mg/yr of citric acid and 195 Mg/yr of soda ash. Citric acid cost is $1,570/Mg and soda ash cost is $100/Mg. References 6, 7, 27, 28.

Table 8-16. CITRATE FGD SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III (continued)

[i] Electricity cost is \$0.0652 per kWh. Basis for electricity requirement was calculated using the following equation:

$$\text{electricity required (kWh} \times 10^6) = 8.2 \times 10^6 \, \frac{a}{4{,}800}^{\,0.7}$$

Where a = gas flow of citrate system being costed, scmm

References 4, 23, 28.

[j] Basis for water requirement for non-water cooled citrate system was given as 151 m^3 per year, for an annual expenditure of \$9.50. Water cost is \$0.0625 per m^3. References 4, 25.

[k] Based on sulfur flow being the major determinant of steam consumption, 79,600 Mg of steam consumed per year for a citrate system recovering 8,100 Mg of sulfur per year, and assuming a relationship for relating different amounts of sulfur recovered the same as for sulfur concentrations in footnote b for major equipment costs; steam consumption was calculated using the following equation:

$$\text{Steam Required} = 79{,}600 \text{ Mg} \, \frac{a}{8{,}100 \text{ Mg}}^{\,0.7}$$

Where: a = kg of sulfur recovered for citrate system whose steam requirement is being determined. Small model unit = 2,141 Mg; large model unit = 6,776 Mg.

References 23, 28.

[l] The only major waste product is crystalline sodium sulfate, Glauber's salt. The basis for the waste disposal requirements is the assumption that the ratio of Glauber's salts produced to sulfur recovered is constant, 67.4 kg Glauber's salt per Mg sulfur recovered. Therefore, requirements are: small model unit (2,141 Mg per year recovered sulfur) = 144.3 Mg per year waste; large model unit (6,776 Mg per year recovered sulfur) = 456.7 Mg per year waste. Waste disposal cost is \$16.50 per Mg. References 23, 28.

[m] Based on 4 percent of total capital cost. Reference 4.

[n] Based on an expected service life of 15 years and an interest rate of 10 percent. Capital recovery cost is calculated by 0.1315 x (total capital cost). Reference 4.

Table 8-16. CITRATE FGD SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III (concluded)

[o] Product recovery credit for elemental molten sulfur is based on $138.3 per Mg. Amount of recovered product is 2,141 Mg per year for the small model plant and 6,776 Mg per year for the large model plant. References 22, 28.

[p] Costs of an electrostatic precipitator (ESP) are credited because a typical citrate system recovering elemental sulfur utilizes a venturi scrubber; however, vendors caution that it remains unproven whether the citrate FGD will provide complete particulate control. ESP costs are given in Table 8-19. Reference 29.

Table 8-17. SPRAY DRYING COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III (Costs Reported in Thousands of Dollars)[a]

	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
TOTAL CAPITAL COSTS[b]	1,780	4,720
Direct Operating Costs		
Operating Labor	29.8	29.8
Maintenance Labor[c]	29.8	29.8
Replacement Material[d]	35.6	94.4
Utilities		
Pebble Lime[e]	110	344
Electricity[f]	112	335
Water[g]	1.8	6.1
Waste disposal[h]	68.4	217
Indirect Operating Costs		
Tax, Insurance, and Administration[i]	71.2	189
Capital Recovery Cost[j]	234	621
TOTAL ANNUAL COSTS	693	1,866
ESP CREDIT[k]	-200	-330
NET ANNUAL COST	493	1,536
EMISSION REDUCTION (Mg SO_2 Removed/year)	1,470	4,710
COST EFFECTIVENESS (\$/Mg of SO_2 Removed)	335	326

Footnotes are on the next page.

Table 8-17. SPRAY DRYING COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED AND REGULATORY ALTERNATIVE III (Concluded)

[a] Nelson cost indexes were used to adjust costs to fourth quarter 1980 dollars.

[b] Capital costs include contingency costs of 20 percent, although vendor estimates may include only 5-10 percent contingency. Depending upon specifications (i.e., standards for motors, pumps, vessel thickness, etc.) actual total capital costs may vary by 15-20 percent. References 30, 31.

[c] Based on 1 man-year per unit (2,080 hours per man-year) and labor charge of $14.35. Reference 30.

[d] Based on 2 percent of total capital cost. Reference 30.

[e] Based on pebble lime requirements of: 2,500 m^3/sd unit = 5.99 Mg/day (6.6 ton/day), 8,000 m^3/sd unit = 18.78 Mg/year (20.7 ton/day). The cost of pebble lime is $42.18 Mg ($46.50/ton). References 30, 32.

[f] Based on electricity requirements of: 2,500 m^3/sd unit = 200 kW; 8,000 m^3/sd unit = 600 kW. Annual electricity requirements of: 2,500 m^3/sd unit = 1,713,600 kWh; 8,000 m^3/sd unit = 5,140,800 kWh. Electricity cost = $0.0652/kWh. References 4, 30.

[g] Based on water requirements of: 2,500 m^3/sd unit = 29,190 m^3/yr; 8,000 m^3/sd unit = 97,290, water cost = $0.0625/$m^3$. References 4, 30.

[h] Based on waste disposal cost of $16.50/Mg. Waste disposal requirements are: 2,500 m^3/sd unit = 4,148 Mg/yr; 8,000 m^3/sd unit = 13,126 Mg/yr. References 4, 33.

[i] Calculated as 4 percent of the total capital cost. Reference 4.

[j] Cost is based on a 15-year life and 10 percent interest. Capital recovery cost is calculated as 0.1315 x total capital cost. Reference 4.

[k] The annual costs for an electrostatic precipitator are credited to the spray drying costs because particulate emissions are controlled in addition to SO_2 emissions. Reference 33.

8.4 OTHER COST CONSIDERATIONS

The cost impacts have thus far been discussed exclusively with reference to sulfur oxides. However, other factors affect the costs to the industry in applying control technology to meet the levels of control specified under the regulatory alternatives. Compliance with several existing environmental, safety, and health statutes impose other costs on the refining industry. A summary of these statutes are listed in Table 8-18.

Although specific costs to the industry to comply with most of the provisions, requirements, and regulations of the existing statutes are unavailable, few refineries are expected to close solely due to the cost of compliance with the standards. However, the total costs may accelerate closings prompted from changing crude supplies and product demand.[37]

The costs incurred by the petroleum refining industry to comply with all health, safety, and environmental regulations are not expected to prevent compliance with the regulatory alternative for sulfur oxides emissions from FCC unit regenerators. Nevertheless, they will likely impact the choice of control techniques refiners will employ to meet the regulatory alternatives. This is evidenced in that flue gas desulfurization, which forms the basis of the costs for the regulatory alternatives, simultaneously offers the refiner the benefit of particulate emission reduction required by the existing FCC unit particulate emission NSPS. However, should a refiner choose to utilize hydrodesulfurization or sulfur oxides reduction catalysts for sulfur oxides control, additional costs would be incurred to control particulate emissions. Table 8-19 provides capital and annualized electrostatic precipitator costs incurred to control particulate emissions.[1, 37-44]

Table 8-18. STATUTES THAT MAY BE APPLICABLE TO THE PETROLEUM REFINING INDUSTRY

Statute	Applicable provision, regulation or requirement of statute
Clean Air Act and Amendments	o State implementation plans
	o National emission standards for hazardous air pollutants Benzene fugitive emissions
	o New source performance standards FCC unit particulte matter FCC unit carbon monoxide Petroleum storage vessels VOC Claus sulfur recovery plants
	o PSD construction permits
	o Non-attainment construction permits
Clean Water Act (Federal Water Pollution Act)	o Discharge permits
	o Effluent limitations guidelines
	o New source performance standards
	o Control of oil spills and discharges
	o Pretreatment requirements
	o Monitoring and reporting
	o Permitting of industrial projects that impinge on wetlands or public waters
	o Environmental impact statements
Resource Conservation and Recovery Act	o Permits for treatment, storage, and disposal of hazardous wastes
	o Establishes system to track hazardous wastes
	o Establishes recordkeeping, reporting, labeling and monitoring system for hazardous wastes
	o Superfund
Occupational Safety & Health Act	o Walking-working surface standards
	o Means of egress standards
	o Occupational health and environmental control standards
	o Hazardous material standards
	o Personal protective equipment standards
	o General environmental control standards
	o Medical and first aid standards
	o Fire protection standards
	o Compressed gas and compressed air equipment
	o Welding, brazing, and cutting standards
Coastal Zone Management Act	o States may veto federal permits for plants to be sited in coastal zone
National Environmental Policy Act	o Requires environmental impact statements
Safe Drinking Water Act	o Requires underground injection control permits
Marine Sanctuary Act	o Ocean dumping permits
Toxic Substances Control Act	o Recordkeeping and reporting
	o Premanufacture notification
	o Labeling, recordkeeping
	o Reporting requirements
	o Toxicity testing

Table 8-19. ELECTROSTATIC PRECIPITATOR COSTS
(Fourth Quarter 1980 Dollars)[a]

Cost Terms	2,500 m^3/sd Unit	8,000 m^3/sd Unit
CAPITAL COSTS		
Equipment Costs		
Control Device[b]	261,000	435,000
Auxiliaries[c]	34,800	65,200
Instruments and Controls[d]	29,600	50,000
Taxes and Freight[e]	23,600	40,000
Installation Costs[f]	492,000	832,000
Total Capital Costs	841,000	1,422,000
ANNUAL COSTS		
Direct Costs		
Operating Labor[g]	16,100	16,100
General Maintenance[h]	16,800	16,800
Replacement Parts[i]	660	1,110
Utilities[j]	9,250	29,700
Waste Disposal[k]	6,430	20,600
Total Direct Costs	49,200	84,300
Indirect Costs		
Overhead[l]	19,600	19,600
Property Tax, Insurance, and Administration[m]	33,600	56,900
Capital Recovery Cost[n]	98,800	167,100
Total Indirect Costs	152,000	244,000
Total Annualized Costs	201,000	328,000

Footnotes are on the next page.

Table 8-19. ELECTROSTATIC PRECIPITATOR COSTS (Concluded)

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[a] Cost indexes were used to bring costs to fourth quarter 1980 dollars. References 1, 39, 40.

[b] Removal efficiency = 95 percent; drift velocity = 0.076 m/sec; plate area for the 2,500 m^3/sd unit = 1,000 m^2, for the 8,000 m^3/sd unit = 3,200 m^2; air flow for the 2,500 m^3/sd unit = 27 m^3/sec, for the 8,000 m^3/sd unit = 87 m^3/sec. Reference 38.

[c] Auxiliaries include bypass ducting: 19.7 m length, 127 cm diameter, 6.4 mm carbon steel, insulated; 2 elbows 6.4 mm carbon steel, insulated; 2 expansion joints; 2 round dampers with automatic controls; and a 23 cm x 4.5 m screw conveyor. References 4, 41, 42.

[d] Instrument and controls calculated as 10 percent of control device and auxiliary equipment cost. Reference 4.

[e] Taxes and freight calculated as 8 percent of control device and auxiliary equipment cost. Reference 4.

[f] Includes indirect and direct installation costs and 20 percent contingency calculated as 141 percent of purchased equipment cost. Reference 4.

[g] Includes operator and supervisor costs. Operating labor costs are based on 1.25 operator man-hours per shift, 3 shifts per day, 365 days per year and $10.25 per man-hour. Supervisor labor costs are included by adding 15 percent to the operator costs. Reference 4.

[h] Includes labor and material costs. Maintenance labor costs are based on 0.75 man-hours per shift, 3 shifts per day, 365 days per year, and $10.25 per man-hour. Material costs are equal to 100 percent of maintenance labor costs. Reference 4.

[i] Based on 0.078 percent of total capital costs. Reference 43.

[j] Based on 0.135 watts/m^2 plate area, 8,760 hours per year, $0.0652 per kWh, and 1,000 m^2 plate area for the small ESP and 3,200 m^2 plate area for the large ESP. Reference 4.

[k] Cost to remove waste is based on $16.50/metric ton. Cost from Reference 4, updated to September 1980, see Reference 3.

[l] Overhead calculated as 80 percent operating labor and maintenance (labor only). Reference 4.

[m] Calculated as 4 percent of total installed capital cost. Reference 4.

[n] Capital recovery cost based on 20 years operating life, and 10 percent annual interest rate. Capital recovery factor = 0.1175. Reference 4.

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9.0 ECONOMIC IMPACT

9.1 INDUSTRY CHARACTERIZATION

9.1.1 General Profile

9.1.1.1 Refinery and Catalytic Cracking Capacity. On January 1, 1980, there were 311 petroleum refineries operating in the United States and Puerto Rico with a total crude capacity of over 3 million m^3 per steam day.[1] Of those refineries 128 operated fluid catalytic cracking (FCC) units with a combined fresh feed capacity of more than .8 million m^3 per stream day.[1] Like overall refinery capacity, over 50 percent of FCC capacity is located in three states: Texas (28%), Louisiana (15%), and California (10%). Table 9-1 summarizes FCC capacity by state, company, and location.

Approximately 30 to 40 percent of the liquids processed by a petroleum refinery pass through the FCC unit. Catalytic cracking is used by the refiner to produce motor fuels and blending stocks from the heavier portions of crude oil, by catalytically splitting the large hydrocarbon molecules in heavy gas oil feedstocks into smaller molecules. Catalytic cracking is also used to increase the yield and quality of gasoline blending stocks and middle distillate fuels.

It should be noted that in the production and capacity tables that follow, a distinction is often made between stream days (i.e., sd) and calendar days (i.e., cd). The basic difference between the two terms is that "stream days" refers to the maximum capacity of a refinery or unit on a given operating day, while "calendar day" production represents the average daily production over a one-year period. Since most refineries do not operate 365 days each year, stream day numbers are always slightly larger than those for calendar days.

9.1.1.2 Refinery Production. In terms of total national output, the percentage yields of various refined petroleum products have remained constant over recent years, although several exceptions are noted below. The

Table 9-1. REFINERIES WITH FLUID CATALYTIC CRACKING UNITS (FCCU) 1980[a]

Company and Refining Location	Fresh Feed Capacity (m^3/Sd)	Recycle (m^3/Sd)
ARKANSAS		
Tosco Corp. - El Dorado	2,466	123
CALIFORNIA		
Atlantic Richfield Co. - Carson	8,909	-
Chevron U.S.A. Inc. - El Segundo	8,273	1,272
Chevron U.S.A. Inc. - Richmond	10,023	-
Exxon Co. U.S.A. - Benecia	7,795	1,749
Gulf Oil Co. U.S. - Santa Fe Springs	2,148	48
Mobil Oil Corp. - Torrance	9,545	-
Powerine Oil Co. - Santa Fe Springs	1,941	48
Shell Oil Co. - Martinez	9,545	-
Shell Oil Co. - Wilmington	5,564	795
Texaco Inc. - Wilmington	4,452	-
Tosco Corp. - Avon	7,472	-
Union Oil of California - Wilmington	7,154	1,113
COLORADO		
Asamera Oil Inc. - Commerce City	1,097	16
DELAWARE		
Getty Refining and Marketing Co. - Delaware City	9,857	2,385
HAWAII		
Chevron U.S.A. Inc. - Honolulu	3,498	-
ILLINOIS		
Amoco Oil Co. - Wood River	6,359	318
Clark Oil & Refining Corp. - Blue Island	4,134	159
Clark Oil & Refining Corp. - Hartford	4,452	159
Marathon Oil Co. - Robinson	6,041	64
Mobil Oil Corp. - Joliet	15,103	-
Shell Oil Corp. - Wood River	14,944	-
Texaco Inc. - Lawrenceville	5,405	-
Texaco Inc. - Lockport	4,769	-
Union Oil Co. of Calif. - Lemont	9,221	795
INDIANA		
Amoco Oil Co. - Whiting	22,258	1,590
Energy Cooperative Inc. - East Chicago	7,154	795
Indiana Farm Bureau Cooperative Association, Inc., - Mount Vernon	1,113	-
Rock Island Refining Corp. - Indianapolis	2,703	-
KANSAS		
CRA, Inc. - Cofferyville	2,941	238
CRA, Inc. - Phillipsburg	1,351	127
Getty Refining and Marketing Co. - El Dorado	4,928	2,703
National Cooperative Refinery Association - McPherson	3,180	-
Pester Refining Co. - El Dorado	1,749	636
Phillips Petroleum Co. - Kansas City	5,326	2,655
Total Petroleum Inc. - Arkansas City	2,607	-
KENTUCKY		
Ashland Oil Inc. - Catlettsburg	9,857	-
Ashland Oil Inc. - Louisville	1,510	-

Table 9-1. (Continued)

Company and Refining Location	Fresh Feed Capacity (m^3/Sd)	Recycle (m^3/Sd)
LOUISIANA		
Cities Service Co. - Lake Charles	23,847	-
Conoco - Westlake	4,865	-
Exxon Co. U.S.A. - Baton Rouge	25,437	-
Good Hope Industries Inc. - Good Hope	10,334	-
Gulf Oil Co. U.S. - Belle Chasse	14,149	336
Marathon Oil Co. - Garyville	11,924	2,226
Murphy Oil Corp. - Meraux	5,612	159
Placid Refining Co. - Port Allen	2,623	159
Shell Oil Co. - Norco	15,898	318
Tenneco Oil Co. - Chalmette	3,577	-
Texaco Inc. - Convent	6,677	-
MICHIGAN		
Marathon Oil Co. - Detroit	4,293	207
Total Petroleum Inc. - Alma	2,544	-
MINNESOTA		
Ashland Oil Inc. - St. Paul Park	3,498	-
Conoco - Wrenshall	1,510	-
Koch Refining Co. - Rosemont	8,426	159
MISSISSIPPI		
Chevron U.S.A. Inc. - Pascagoula	8,903	318
MISSOURI		
Amoco Oil Co. - Sugar Creek	6,677	1,908
MONTANA		
Conoco - Billings	2,385	79
Exxon Co. U.S.A. - Billings	3,339	1,590
Farmers Union Central Exchange Inc. - Laurel	1,908	477
Phillips Petroleum Co. - Great Falls	334	199
NEBRASKA		
CRA, Inc. - Scottsbluff	382	79
NEW JERSEY		
Exxon Co. U.S.A. - Linden	21,463	4,769
Texaco Inc. - Westville	6,359	-
NEW MEXICO		
Navajo Refining Co. - Artesia	890	64
Plateau Inc. - Bloomfield	874	79
Shell Oil Co. - Gallup	1,145	572
NEW YORK		
Ashland Oil Inc. - Buffalo	3,498	-
NORTH DAKOTA		
Amoco Oil Co. - Mandan	4,134	827
OHIO		
Ashland Oil Inc. - Canton	4,134	-
Gulf Oil Co. U.S. - Cleves	2,862	318
Gulf Oil Co. U.S. - Toledo	3,148	318
Standard Oil Co. of Ohio - Lima	5,994	1,240
Standard Oil Co. of Ohio - Toledo	8,744	2,623
Sun Co. Inc. - Toledo	7,949	1,192

Table 9-1. (Continued)

Company and Refining Location	Fresh Feed Capacity (m^3/Sd)	Recycle (m^3/Sd)
OKLAHOMA		
Champlin Petroleum co. - Enid	3,100	48
Conoco - Ponca City	7,154	-
Hudson Refining Co. Inc. - Cushing	1,192	-
Kerr McGee Corp. - Wynnewood	3,180	64
Oklahoma Refining Co. - Cyril	1,113	159
Sun Co. Inc. - Duncan	3,975	1,669
Sun Co. Inc. - Tulsa	4,769	223
Texaco Inc. - Tulsa	2,862	-
Vickers Petroleum Corp. - Ardmore	3,418	159
PENNSYLVANIA		
BP Oil Corp. - Marcus Hook	7,631	254
Gulf Oil Co. U.S. - Philadelphia	13,450	1,033
Sun Co. Inc. - Marcus Hook	11,924	2,385
United Refining Co. - Warren	1,908	32
TEXAS (Inland)		
American Petrofina Co. of Texas - Big Spring	3,657	-
Chevron U.S.A. Inc. - El Paso	3,498	-
Diamond Shamrock Corp. - Sunray	5,167	-
La Gloria Oil and Gas Co. - Tyler	1,590	795
Phillips Petroleum Co. - Borger	8,267	1,653
Shell Oil Co. - Odessa	1,669	874
Texaco Inc. - Amarillo	1,272	-
Texaco Inc. - El Paso	1,113	-
Winston Refining Co. - Forth Worth	556	238
TEXAS (Gulf)		
American Petrofina Co. of Texas - Port Arthur	5,405	318
Amoco Oil Co. - Texas City	29,253	5,246
Atlantic Richfield Co. - Houston	12,401	795
Champlin Petroleum Co. - Corpus Christi	10,970	-
Charter International Oil Co. - Houston	7,313	-
Coastal States Petroleum Co. - Corpus Christi	3,021	-
Crown Central Petroleum Corp. - Pasedena	7,949	-
Exxon Co. U.S.A. - Baytown	27,027	2,385
Gulf Oil Co. U.S. - Port Arthur	19,078	954
Marathon Oil Co. - Texas City	6,041	159
Mobil Oil Corp. - Beaumont	15,739	-
Phillips Petroleum Co. - Sweeney	5,882	827
Shell Oil Co. - Deer Park	11,129	-
Southwestern Refining Co. Inc.-Corpus Christi	1,908	111
Sun Co. Inc. - Corpus Christi	3,975	1,033
Texaco Inc. - Port Arthur	21,463	-
Texas City Refining Inc. - Texas City	6,359	-
Union Oil Co. of California - Nederland	6,041	636
UTAH		
Amoco Oil Co. - Salt Lake City	2,862	636
Chevron U.S.A. Inc. - Salt Lake City	2,862	159
Plateau Inc.- Roosevelt	827	-
VIRGINIA		
Amoco Oil Co. - Yorktown	4,452	795
WASHINGTON		
Shell Oil Co. - Anacortes	5,723	2,703
Texaco Inc. - Anacortes	4,769	-
WISCONSIN		
Murphy Oil Corp. - Superior	1,510	159

Table 9-1. (Continued)

Company and Refining Location	Fresh Feed Capacity (m^3/Sd)	Recycle (m^3/Sd)
WYOMING		
Amoco Oil Co. - Casper	2,067	238
Husky Oil Co. - Cheyenne	1,590	397
Husky Oil Co. - Cody	604	181
Sinclair Oil Corp. - Sinclair	3,339	-
Texaco Inc. - Casper	1,113	-
PUERTO RICO		
Caribbean Gulf Refining Corp. - Bayamon	1,033	-
Commonwealth Oil Refining Co., Inc.-Panuelas	6,359	636
TOTAL	809,709	65,958

[a]Reference 1, pp. 24-36.

percentage yields of refined petroleum products from crude oil for the years 1969 through 1978 are summarized in Table 9-2, while Table 9-3 notes the average daily output of the major products.

Among the major products of U.S. refineries are gasoline and distillate fuel oil, accounting for about 44 and 22 percent of total refinery output respectively. Other products of refineries are residual fuel oil, jet fuel, and petrochemical feedstocks.

Through the 1970's residual fuel oil and petrochemical feedstocks have accounted for increasing shares of total refinery output. These increases can be traced to the use of residual fuel oil in industrial applications and the growth in petrochemical markets due to the increased production of synthetic rubber, fibers, plastics, and other materials manufactured from petrochemicals. The increased output of residual fuel oil and petrochemicals have been balanced by declining output of gasoline and kerosene.

9.1.1.3 Refinery Ownership, Vertical and Horizontal Integration. A large portion of domestic refining capacity is owned and operated by large, vertically integrated oil companies, both domestic and international. The remainder is controlled by independent refiners such as Charter, Crown Central Petroleum, Holly, Tosco, and United Refining.

Table 9-4 lists twenty companies with the greatest capacity to process crude oil. Based upon the capacities noted, and a total domestic capacity of 3,005,000 m^3 per stream day,[1] the 4- and 8-firm concentration ratios are 29 and 48 percent, respectively. Since there are currently 158 companies[1] engaged in refining activities, these ratios are indicative of a high degree of ownership concentration of refinery capacity.

Refinery ownership is but one aspect of the vertical integration of the major oil companies. Such companies are integrated "backward" in that they own or lease crude oil production facilities, both domestic and international, as well as the means to transport crude by way of pipeline and tankers. On the other hand, "forward" integration is less extensive in that most retail outlets are operated by franchise agreements as noted below.

With regard to transportation by pipeline, the major oil companies have been the main source of capital for the construction and operation of

Table 9-2. PERCENTAGE VOLUME YIELDS OF REFINED PETROLEUM PRODUCTS FROM CRUDE OIL IN THE U.S. 1971-1978[a]

Product	1971	1972	1973	1974	1975	1976	1977	1978
Motor Gasoline	46.2	46.2	45.6	45.9	46.5	45.5	43.4	44.1
Jet Fuel	7.4	7.2	6.8	6.8	7.0	6.8	6.6	6.6
Ethane	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Liquefied Gases	2.9	2.8	2.8	2.6	2.4	2.4	2.3	2.3
Kerosene	2.1	1.8	1.7	1.3	1.2	1.1	1.2	1.2
Distillate Fuel Oil	22.0	22.2	22.5	21.8	21.3	21.8	22.4	22.4
Residual Fuel Oil	6.6	6.8	7.7	8.7	9.9	10.3	12.0	12.0
Petrochem. Feedstocks	2.7	2.9	2.9	3.0	2.7	3.3	3.6	3.6
Special Naphthas	0.7	0.7	0.7	0.8	0.6	0.7	0.6	0.6
Lubricants	1.6	1.5	1.5	1.6	1.2	1.3	1.2	1.2
Wax	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Coke	2.6	2.8	2.9	2.8	2.8	2.6	2.5	2.5
Asphalt	3.8	3.6	3.6	3.7	3.2	2.8	2.9	2.9
Road Oil	0.2	0.2	0.2	0.2	0.1	0.0	0.1	0.1
Still Gas	3.8	3.9	3.9	3.9	3.9	3.7	3.6	3.6
Miscellaneous	0.4	0.4	0.4	0.5	0.7	1.0	1.0	1.0
Processing Gain	- 3.4	- 3.3	- 3.6	- 3.9	- 3.7	- 3.5	- 3.6	- 3.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[a]Reference 2.

Table 9-3. PRODUCTION OF PETROLEUM PRODUCTS AT UNITED STATES REFINERIES 1969-1978[a] (1,000 m^3/cd)

Year	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel	Kerosene	NGL and LRG[b]
1969	872	370	116	140	45	54
1970	909	391	112	131	42	55
1971	951	397	120	133	38	57
1972	1,000	419	127	135	35	57
1973	1,039	449	154	137	35	60
1974	1,011	424	170	133	25	54
1975	1,037	422	197	138	24	49
1976	1,088	465	219	146	24	54
1977	1,118	521	279	155	27	56
1978	1,140	501	266	155	24	--

[a] Reference 2. Section VII. Tables 5, 6, 6a, 7, 7a, 14, 15, 16, 16a, 17, and 17a.

[b] NGL = Natural Gas Liquids; LRG = Liquefied Refinery Gases.

Table 9-4. REFINERY FACILITIES OF MAJOR COMPANIES[a]

Company	Number of Refineries	Crude Capacity (1,000 m^3/cd)
Exxon	5	251
Chevron	12	233
Amoco	10	197
Shell	8	183
Texaco	12	168
Gulf	7	145
Mobil	7	142
ARCO	4	133
Marathon	4	93
Union Oil	4	78
Sun	5	77
Sohio/BP	3	72
Ashland	7	73
Phillips	5	68
Conoco	7	58
Coastal States	3	47
Cities Service	1	46
Champlin	3	38
Tosco	3	35
Getty	2	35

[a] Reference 3, p. 075.

these facilities, due largely to the huge investments required. On the other hand, tanker ownership is divided among the major oil companies and independent operators who charter tankers to oil companies and traders.[4] The presence of independent tanker operators is a result of relatively small financial requirements, compared to pipeline ownership.

While many of the low-volume refinery products are marketed directly by the refiners themselves, the sale of gasoline on the retail level is handled primarily by franchised dealers and independent operators. The major refiners do, however, have a high degree of control over the distribution of their products with regard to market area. This is so since the major refiners select sites for the construction of service stations before the facilities are leased to independent operators under franchise agreements. The major refiners do maintain the direct operation of some service stations for purpose of measuring the strength of the retail market. However, no more than 5 percent of all facilities in operation are managed in this fashion.[5]

Many of the firms that operate refineries, notably the larger oil companies, are diversified as well as vertically integrated. A natural area of diversification for refiners is the manufacture of petrochemicals and resins. Among the firms that have interests in these areas are: Clark Oil and Refining, Getty Oil, Occidental Petroleum, and Phillips Petroleum. Ashland Oil's construction division operates the largest highway paving company as well as two shipyards. Exxon Enterprises develops and manufactures various high-technology products. The Kerr-McGee Corporation is the largest supplier of commercial grade uranium for electricity generation and also manufactures agricultural and industrial chemicals. Mobil Oil Corp. is owned by Mobil Corp. which owns both Montgomery Ward and Co. and The Container Corporation of America. The Charter Co., the largest of the independent refiners, is also engaged in broadcasting, insurance, publishing, and commercial printing.

9.1.1.4 Refinery Employment and Wages. Total employment at domestic petroleum refineries has grown steadily since the mid-1960's, with minor disruptions due to the recessions of 1970 and 1974. As Table 9-5 demonstrates, there were 163 thousand workers employed at refineries in 1978.[6] With 289 refineries operating that year,[7] average employment at each refinery is approximately 564 persons.

Table 9-5. EMPLOYMENT IN PETROLEUM AND NATURAL GAS EXTRACTION AND PETROLEUM REFINING 1969-1978[a]

(1,000 Workers)

Year	Petroleum and Natural Gas Extraction	Petroleum Refining
1969	279.9	144.7
1970	270.1	153.7
1971	264.2	152.7
1972	268.2	152.3
1973	277.7	149.9
1974	304.5	155.4
1975	335.7	154.2
1976	360.3	157.1
1977	404.5	160.3
1978	417.1	163.0

[a] Reference 2. Section V. Table 2.

The average hourly earnings of petroleum refinery workers have consistently exceeded average wage rates for both the mining and manufacturing industries.[8] Petroleum refinery hourly earnings have also exceeded those for other sectors of the oil industry as noted in Table 9-6.

9.1.1.5 Gasoline Pool. The largest single product produced at petroleum refineries is motor gasoline. This product is essentially a blend of the products of several different refinery units including the catalytic cracking unit. Table 9-7 provides a summary of the estimated contributions of individual refinery streams to the gasoline pool. As noted in that Table FCC gasoline is estimated to make the largest single contribution to total gasoline output.

9.1.2 Market Factors

9.1.2.1 Demand Determinants. 1980 DOE projections conclude that, on the national level, existing refinery capacity is capable of satisfying the future domestic demand for refined petroleum products.[10] Expansions and modifications will, however, be undertaken in order to allow the processing of greater proportions of high-sulfur crudes, and to permit the production of increasing levels of high-octane unleaded gasoline. It is also possible that shifts in demand on the regional level may call for capacity expansions at existing refineries.[10]

Evidence of sufficient refining capacity is provided by Table 9-8. In that table estimates of percent refinery capacity utilization, along with daily demand levels for the four major refinery products, are presented under several assumptions regarding the world price of oil. In each case the projected utilization rate is well below the 1978 level of 86 percent.

Reduced driving and greater vehicle efficiency have combined to reduce the future demand for motor gasoline. As Table 9-8 indicates, it is unlikely that gasoline demand will, within the forecast period, reach those levels observed during 1978. This conclusion holds true regardless of specific assumptions concerning the future of world oil prices.

Reduced total gasoline demand does not, however, imply that existing gasoline production facilities are currently capable of meeting future gasoline requirements. In particular the continued phase-out of leaded gasoline and demand for higher octane ratings will require some additions to refinery capacity. Consequently, refiners can be expected to increase

Table 9-6. AVERAGE HOURLY EARNINGS OF SELECTED INDUSTRIES[a]
(Average Hourly Wage)

Year	Petroleum Refining	Petroleum and Natural Gas Extraction	Total Manufacturing	Total Mining
1969	4.23	3.43	3.19	3.61
1970	4.49	3.57	3.36	3.85
1971	4.82	3.75	3.57	4.06
1972	5.25	4.00	3.81	4.41
1973	5.54	4.29	4.08	4.73
1974	5.96	4.82	4.41	5.21
1975	6.90	5.34	4.81	5.90
1976	7.75	5.76	5.19	6.42
1977	8.44	6.23	5.63	6.88
1978	9.32	7.01	6.17	7.67

[a] Reference 2. Section V. Table 1.

Table 9-7. ESTIMATED 1981 UNITED STATES GASOLINE POOL COMPOSITION[a]

Stream	Amount (1,000,000 m^3/cd)	% of Total
Reformate	355	29.9
FCC Gasoline	408	34.4
Alkylate	162	13.7
Raffinate	17	1.4
Butanes	75	6.3
Coker Gasoline	15	1.3
Natural Gasoline	30	2.5
Light Hydrocrackate	22	1.9
Isomerate	16	1.3
Straight Run Naphtha	86	7.3
Total	1,186	100.0

[a] Reference 9.

Table 9-8. DEMAND PROJECTIONS FOR MAJOR PETROLEUM PRODUCTS[a]

Year	World Oil Price (1979 $/m^3)	Refinery Capacity (1,000 m^3/cd)	Capacity Utilization (Percent)	Product Demand (1,000 m^3/cd) Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel
1978	97	2,719	86	1,176	572	477	175
1985							
Low	170	3,068	70	1,017	493	223	238
Mid	201	3,068	65	986	461	207	175
High	245	3,068	64	922	445	191	223
1990							
Low	170	3,148	74	1,017	541	238	270
Mid	233	3,148	66	938	493	191	191
High	277	3,148	63	859	461	175	238
1995							
Low	170	3,211	76	1,097	588	207	318
Mid	258	3,211	65	986	493	111	207
High	352	3,211	60	859	429	95	254

[a] Reference 10, p. 115.

catalytic cracking, catalytic reforming, and alkylation capacities in order to maintain octane requirements.[11]

Distillate fuel oils are used in home heating, utility and industrial boilers, and as diesel fuel. In all applications demand is expected to fall with the exception of diesel fuel.[10] Declining demand is essentially due to the availability of lower cost substitutes, in particular coal fired utility and industrial boilers and natural gas for home heating purposes. As indicated in Table 9-8, the demand for distillate fuel oil declines in all cases with the exception of low crude oil prices in 1995.

Residual fuel oil is used as a bunker fuel in large ships, large utility and industrial boilers, and in the heating of some buildings. Residual fuel oil competes with coal for use as a fuel in the applications noted above. Table 9-8 shows that the demand for residual fuel oil falls steadily under all price scenarios. This is so because the ability to crack residual fuel into more valuable lighter products ensures that its price will not fall to that point where it can serve as a cost-effective replacement for coal.[12]

The elasticity of demand is a measure of the percentage change in demand relative to a percentage change in price. With regard to the elasticity of demand for petroleum products, most econometric studies conclude that short-run demand is not sensitive to price changes. Estimates made by the Department of Energy and summarized in Table 9-9, support this conclusion.[13] Since all values in the table are less than one, the general conclusion is that short-term demand is not particularly sensitive to price changes.

9.1.2.2 Supply Determinants. As noted in the previous section, it is unlikely that the supply of refined petroleum products will be restricted for reason of inadequate domestic refining capacity. It is, however, quite possible that disruptions in the flow of imported oil could result from international developments, in particular, political instability in the Middle East. The major thrust of national energy policy is therefore the reduction of dependence upon imported oil.

Attempts to reduce dependence upon imported oil have focused upon three major areas: reduced consumption through conservation, and increased domestic production through both the decontrol of domestic oil prices and the development of a synthetic fuels industry. While price decontrol and synthetic fuels development may have a significant impact in terms of import reductions, these

Table 9-9. PRICE ELASTICITIES FOR MAJOR REFINERY PRODUCTS BY SECTOR[a]
(1985)

Sector	Product	Elasticity
Residential	Distillate Oil	-0.37
Commerical	Distillate Oil	-0.41
Industrial	Distillate Oil	-0.53
	Residual Oil	-0.36
	Liquid Gas	-0.45
Transportation	Gasoline	-0.29
	Distillate Oil	-0.66
	Residual Oil	-0.10
	Jet Fuel	-0.42

[a] Reference 10, pp. 332-3, short-term elasticities.

measures are essentially mid- to long-term solutions. Conservation, on the other hand, has offered more immediate results.

The effects of recent conservation efforts, including decreased gasoline consumption, and conversion of facilities to coal and natural gas, can be observed in Table 9-10. In particular, imports of crude oil have leveled-off after reaching a historic high of 384 million m^3 in 1977, while recent reports[14] indicate that the reduction of imports has continued into 1980. The results of conservation efforts can also be observed in the fact that year-end stocks of crude are currently at the highest levels recorded in the recent past.

The phasing out of price controls on crude domestic oil and refined petroleum products was completed on January 28, 1981 with the issuance of E.O. 12287, which revoked the price and allocation controls granted to the Department of Energy under the Emergency Petroleum Allocation Act of 1973. The progressive decontrol of domestic crude oil prices has increased exploration, and is expected to increase stocks of already proven reserves. Recent increases in both drilling activities and proven reserves are noted in Table 9-11.

The development of a domestic synthetic fuels industry will have little impact upon energy supplies over the next five years since significant output is not anticipated until the late 1980s.[15]

9.1.2.3 Prices. Table 9-12 indicates recent price levels for gasoline, distillate fuel oil, and residual fuel oil. For each product, a pattern of stable prices, followed by rapid price increases in 1974 and 1979, can be observed. The increases in both years are attributed to the pass-through of increases in the price of crude oil supplied by the OPEC nations.

Future refined product prices will continue to rise in response to increases in the long-term price of both imported and domestic crude. Table 9-13 presents recent DOE projections of world oil, gasoline, distillate fuel oil, residual fuel oil, and jet fuel prices.

9.1.2.4 Imports. Imports of both crude oil and refined products are expected to decline through the mid-1980's. In the case of crude oil, the fall in import levels can be attributed to sharp increases in the price of OPEC oil, and the increased production of domestic crude prompted by its price decontrol.

Table 9-10. CRUDE OIL STATISTICS[a]
(1,000,000 m^3/year)

Year	Domestic Production	Imports	Domestic Consumption	Exports	Year-End Stocks	Stocks as Percent of Consumption
1970	559	77	633	0.8	44	6.94
1971	549	98	649	0.1	41	6.36
1972	549	129	680	0.1	39	5.76
1973	534	188	723	0.1	39	5.33
1974	486	202	688	0.2	42	6.13
1975	465	238	703	0.3	43	6.14
1976	452	308	760	0.5	45	5.97
1977	457	384	841	2.9	55	6.57
1978	485	369	854	9.2	60	7.01
1979	474	376	850	13.6	68	8.05

[a] Reference 3, p. 073.

Table 9-11. DOMESTIC OIL EXPLORATION AND DISCOVERIES

Year	Exploratory Wells Drilled	New Reserves Added (1,000,000 m^3)
1970	7,693	1,566[b]
1971	7,000	15
1972	8,357	20
1973	7,466	18
1974	8,619	36
1975	9,163	28
1976	9,234	11
1977	9,961	25
1978	10,667	32
1979	10,484	38

[a] Reference 3, p. 072.

[b] Includes Prudhoe Bay, Alaska.

Table 9-12. PRICES: GASOLINE, DISTILLATE FUEL OIL, AND RESIDUAL FUEL OIL

Year	Gasoline (¢/liter) Wholesale[a]	Gasoline (¢/liter) Retail[b]	Distillate Fuel Oil (¢/liter) Wholesale[a]	Distillate Fuel Oil (¢/liter) Retail[c]	Residual Fuel Oil (¢/liter) Wholesale[a]
1968	4.4	8.9	2.7	4.6	1.5
1969	4.5	9.2	2.7	4.7	1.5
1970	4.7	9.4	2.9	4.9	1.9
1971	4.8	9.6	3.1	5.2	2.6
1972	4.7	9.5	3.1	5.2	3.0
1973	5.2	10.3	3.6	6.0	3.4
1974	8.1	13.8	5.6	9.5	6.8
1975	9.5	15.1	8.2	10.3	6.8
1976	10.3	15.7	8.7	11.0	6.6
1977	11.2	16.7	9.8	12.5	7.9
1978	11.8	17.4	9.9	13.4	7.4
1979	16.4	23.2	14.3	19.2	10.2

[a] Excludes tax: Reference 3, p. 079.

[b] Service station price, regular gasoline, includes tax: Reference 2, Section VI, Table 4.

[c] Reference 2, Section VI, Table 5.

Table 9-13. PRICE PROJECTIONS[a]

(1979 $/m^3)

Year	World Oil Price	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel
1978	97	153	107	80	113
1985					
Low	170	240	185	175	195
Mid	201	277	211	204	221
High	245	320	252	243	263
1990					
Low	170	241	187	176	197
Mid	233	309	242	232	252
High	277	352	295	279	314
1995					
Low	170	240	190	178	199
Mid	258	338	267	255	279
High	352	432	365	352	387

[a] Reference 10, p. 115.

Low sulfur (sweet) crudes are generally more desirable than high sulfur (sour) crudes because the refining of the latter requires a larger investment in desulfurization capacity such as hydrorefining and hydrotreating units. While current crude imports are more than half sweet, only 15 percent of OPEC's total oil reserve is sweet crude.[16] Consequently, it is unlikely that the sweet-sour crude import balance will remain constant. The price differential between the two will eventually make sour crude processing a necessary investment.

With regard to refined petroleum products, the importation of most of these products is expected to decline as it has since the mid-1970's. Table 9-14 shows that for the major refined products, imports peaked during 1973-1974. In general, imports of refined products have been relatively small compared with production at domestic refineries (see Table 9-4). For this reason, the potential for foreign trade disruption is minimized.

9.1.2.5 Exports. Exports of crude oil and refined petroleum products are a small portion of total U.S. production, and amount to less than 8 percent of the volume imported.[17] All exports are controlled by a strict licensing policy administered by the U.S. Department of Commerce. Recently, crude oil exports have increased in response to the Canada-United States Crude Oil Exchange Program. The program is mutually beneficial in that acquisition costs are minimized through improved efficiency of transportation.

Table 9-15 summarizes recent trends in major refined product exports. The decline in exports through the 1970s can be attributed to both increased domestic demand and the expansion of foreign refining capacity.

9.1.3 Financial Profile

Despite the recent softening in product prices, the oil industry is generally regarded as financially strong. This optimistic outlook is attributed to: increases in proven domestic reserves and production, and decreases in the prices and the level of imported oil.

Table 9-14. IMPORTS OF REFINED PETROLEUM PRODUCTS[a] (1,000 m^3/cd)

Year	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel	Kerosene	NGL and LRG
1969	10	22	201	20	0.5	6
1970	11	24	243	23	0.6	8
1971	9	24	252	29	0.2	17
1972	11	29	277	31	0.2	28
1973	21	62	295	34	0.3	38
1974	32	46	252	26	0.8	34
1975	29	25	194	21	0.5	29
1976	21	23	225	12	1.4	31
1977	34	40	216	12	3.0	32
1978	31	27	214	14	1.7	N/A
1979[b]	27	14	178	11	1.4	N/A

[a] Reference 2. Section VII.

[b] Reference 18.

Table 9-15. EXPORTS OF REFINED PETROLEUM PRODUCTS[a]
(1,000 m^3/cd)

Year	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel	Kerosene	NGL and LRG
1969	0.3	0.5	7.3	0.8	0.2	5.6
1970	0.2	0.5	8.6	1.0	-	4.3
1971	0.2	1.3	5.7	0.6	0.2	4.1
1972	0.2	0.5	5.2	0.3	-	4.9
1973	0.6	1.4	3.7	0.8	-	4.3
1974	0.3	0.3	2.2	0.3	-	4.0
1975	0.3	0.2	2.4	0.3	-	4.1
1976	0.5	0.2	1.9	0.3	-	4.0
1977	0.3	0.2	1.0	0.3	-	2.9
1978	0.2	0.5	2.1	0.2	-	N/A

[a] Reference 2. Section VII.

Profit margins (i.e., net profit/sales) and return on investment (i.e., net profit/total investment) for both major oil companies and independent refiners are summarized in Tables 9-16 and 9-17. The general pattern observed is one of increases in both margins and returns through the five year period noted.

It should be noted that the margins and returns presented in both tables are for companies that refine crude oil but are not necessarily indicative of the profitability of refining activities themselves. An indication of the profitability of refining activities alone is provided by Table 9-18, which summarizes the determination of industry profit margins by quarterly intervals.

9.2 ECONOMIC ANALYSIS

9.2.1 Introduction and Summary

In the following sections the economic impacts of the regulatory alternatives are estimated based on the costs of sodium-based flue gas desulfurization. Economic impacts are presented in terms of the potential price, profitability, and capital availability consequences of each regulatory alternative.

For reasons noted in the following sections, it is most likely that the regulatory alternatives presented in Chapter 6 will result in slight increases in the prices of refined petroleum products. In most cases the maximum price increases possible are less than 0.4 percent. It is not expected that the regulatory alternatives would cause the postponement of planned FCC investments at existing refineries.

These conclusions are based upon observation of current market trends and conditions along with the capital and annual cost estimates discussed in the previous section. In the sections that follow a complete description of the methods used to project economic impacts is presented in Section 9.2.2 while the results of the application of those methods are noted in Section 9.2.3.

9.2.2 Economic Impact Methodology

9.2.2.1 Price Impact Methodology. The complete pass-through of the NSPS control costs presented in Chapter 8 will cause increases in the prices of refined petroleum products. The extent of such price increases have been estimated through the expression of the annualized control costs, of each model unit and regulatory alternative, as a percentage of the annual revenues of the refinery in which the new unit is likely to be constructed. The percentages are therefore indicators of the extent to which refinery revenues, and

Table 9-16. PROFIT MARGINS[a]

	1975	1976	1977	1978	1979
Integrated-International					
British Petroleum	1.9	1.7	3.0	3.1	8.9
Exxon Corp.	5.6	5.4	4.5	4.6	5.4
Gulf Oil	4.9	5.0	4.2	4.4	5.5
Mobil Corp.	3.9	3.6	3.1	3.2	4.5
Royal Dutch Petroleum	6.7	7.2	6.0	5.0	11.1
Standard Oil (Calif.)	4.6	4.5	4.9	4.8	6.0
Tesoro Petroleum	5.3	2.7	0.1	2.4	2.5
Texaco, Inc.	3.4	3.3	3.3	3.0	4.6
Integrated-Domestic					
Amerada Hess	4.0	3.9	3.9	3.0	7.5
Ashland Oil	3.3	3.3	3.4	4.7	8.1
Atlantic Richfield	4.8	6.8	6.4	6.5	7.2
Cities Service	4.3	5.5	4.8	2.5	5.5
Clark Oil and Refining	0.9	1.3	1.6	1.6	3.6
Conoco, Inc.	4.6	5.8	4.4	4.8	6.4
Earth Resources	4.5	4.6	4.5	2.9	4.1
Getty Oil	8.6	8.5	9.9	9.3	12.5
Kerr-McGee	7.3	6.9	5.5	5.7	6.0
Marathon Oil	4.5	5.6	4.6	4.4	4.4
Phillips Petroleum	6.7	7.2	8.2	10.2	9.4
Shell Oil	6.3	7.6	7.3	7.4	7.8
Standard Oil (Indiana)	7.9	7.7	7.6	7.2	8.1
Standard Oil (Ohio)	5.1	4.7	5.2	8.7	15.0
Sun Co.	5.0	6.6	5.6	4.9	6.6
Union Oil of California	4.6	5.0	5.9	6.4	6.6
Refiners					
Charter Co.	1.0	1.5	1.3	1.2	8.7
Crown Central Petroleum	1.2	2.4	2.0	2.8	6.8
Holly Corp.	3.1	4.0	3.8	3.5	2.6
Tosco Corp.	N/A	0.9	1.2	1.6	4.1
United Refining	1.8	0.8	2.1	2.1	3.4

[a] Reference 12, p. 088.

Table 9-17. RETURN ON INVESTMENT[a]

	1975	1976	1977	1978	1979
Integrated-International					
British Petroleum	2.0	2.1	4.3	4.1	11.8
Exxon Corp.	7.8	7.6	6.5	6.9	9.5
Gulf Oil	5.6	6.3	5.4	5.4	8.2
Mobil Corp.	5.6	5.5	5.1	5.2	8.0
Royal Dutch Petroleum	6.8	8.4	8.0	6.0	13.5
Standard Oil (Calif.)	6.3	6.6	7.1	7.0	10.2
Tesoro Petroleum	9.0	4.0	0.2	5.3	9.9
Texaco, Inc.	4.8	4.9	5.0	4.4	8.1
Integrated-Domestic					
Amerada Hess	5.5	5.9	6.0	4.2	11.3
Ashland Oil	6.3	6.6	6.7	8.8	20.2
Atlantic Richfield	5.2	7.1	6.8	6.7	8.9
Cities Service	4.5	6.3	5.7	3.0	7.9
Clark Oil and Refining	1.7	3.0	4.5	4.9	10.6
Conoco, Inc.	6.7	8.0	6.0	6.4	9.7
Earth Resources	12.9	12.8	10.9	7.2	8.5
Getty Oil	8.2	7.5	8.0	7.4	11.2
Kerr-McGee	10.1	8.9	6.9	6.1	7.3
Marathon Oil	6.7	7.8	6.1	5.5	7.3
Phillips Petroleum	8.0	8.5	9.5	11.1	11.5
Shell Oil	7.8	9.4	8.7	8.3	8.4
Standard Oil (Indiana)	8.4	8.5	8.4	8.0	9.6
Standard Oil (Ohio)	3.6	2.6	2.3	5.0	13.4
Sun Co.	5.2	7.8	6.6	6.8	10.2
Union Oil of California	6.3	6.3	7.0	7.3	8.7
Refiners					
Charter Co.	2.0	3.2	3.2	3.4	29.1
Crown Central Petroleum	2.9	5.3	5.1	6.4	16.8
Holly Corp.	9.1	11.1	10.6	9.9	8.0
Tosco Corp.	N/A	2.6	2.8	4.2	14.2
United Refining	5.0	2.1	5.6	6.2	11.0

[a] Reference 12, p. 087-088.

Table 9-18. PETROLEUM REFINING - INCOME DATA[a]
($1,000,000)

	1978				1979				1980
	1	2	3	4	1	2	3	4	1
Sales	41.75	43.88	46.17	48.52	50.72	54.71	63.68	73.58	79.80
Net Income Before Tax	3.05	3.77	4.14	4.23	4.65	6.16	6.62	7.81	8.55
Net Income	2.55	3.15	3.41	3.66	3.95	5.25	5.71	6.84	8.04
% Net Income to Sales[b]	6.11	7.18	7.39	7.54	7.79	9.60	8.97	9.30	10.08

[a] Reference 12, p. 082.

[b] Profit margin.

thus the prices of refined petroleum products, would need to increase if the profit margin on sales of refining activities is to remain unaffected.

The annualized cost estimates used to project price increases are presented in Tables 8-4 through 8-9, and Tables 8-11 and 8-12. In those tables separate cost estimates are made for various model units, sulfur contents of feedstocks, regulatory alternatives and the use of caustic soda vs. soda ash. Refinery revenue estimates have been made through the method described below.

The addition of FCC capacity enables a refinery to increase the value of its product mix, producing more of the higher priced components. Therefore an important element in both the price and profitability analyses is the estimation of increased revenues made possible by the added FCC capacity. Refinery revenues before and after the FCC addition have been estimated according to a three-step process:

- o Estimate refined product yields before and after FCC addition,
- o Estimate refined product prices with price decontrol, and
- o Estimate refinery revenues before and after FCC addition.

Each of the steps noted above are discussed in greater detail following the identification of six assumptions used to allow the estimation of refinery revenues. Sources of data are also noted for the assumptions listed below.

First, it is assumed that the smaller model unit (2,500 m^3/sd) is added to a small refinery (8,000 m^3/sd)[20], while the larger model unit (8,000 m^3/sd) is constructed at a large refinery (40,000 m^3/sd).[20]

Second, the product yields for a typical refinery, oriented toward gasoline production are: gasoline (51.1%), distillate (26.0%), residual (13.9%), and kerosene (9.0%)[2], while the ratio of FCC capacity to crude distillation capacity for such a refinery is 40 percent.[21]

Third, it is assumed that the addition of FCC capacity will increase the refinery FCC to crude distillation ratio so that the average ratio before and after the addition is 40 percent. Therefore, the small refinery will have increased FCC capacity 32 percent (i.e. 2,500/8,000) from 24 to 56 percent, while the large refinery will show a 20 percent increase (i.e. 8,000/40,000) from 30 to 50 percent.

Fourth, the product yields for FCC output are: gasoline (68.0%), distillate (21.0%), and residual (11.0%).[21]

Fifth, it is assumed that additional FCC capacity will operate at full capacity and that the total crude distillation capacity of the refinery remains unchanged.

Sixth, the price decontrol of domestic crude and refined petroleum products will add \$25.20/m^3 to the average price of crude and this increase will be passed-on to the price of refined products.[22]

The first step in the revenue estimation process is the determination of refinery product yields before and after the addition of FCC capacity. This has been accomplished through the assumption that 2,500 m^3/sd of the non-kerosene output of the smaller refinery will take the form of the FCC product yields noted in the fourth assumption, while the remainder of output will continue in the form of the typical refinery yields presented in the second assumption. Likewise, the larger refinery will have 8,000 m^3/sd of its non-kerosene output take the form of the FCC product yields. Non-kerosene output is of concern since the output of kerosene should not be significantly altered by a change in FCC capacity. The results of this procedure are presented in Table 9-19.

The decontrol of domestic crude oil and refined petroleum products was completed on January 28, 1981 with the issuance of E.O. 12287. However, all costs and revenues reported in this analysis are expressed in terms of 1980 (IV) dollars. So that the effect of decontrol upon product prices, and thus refinery revenues may be accurately reflected, the November 1980 prices[23] of refinery products have been adjusted to include the pass-through of \$25.2/m^3 as noted in the sixth assumption.[22] Product prices used in this analysis are: gasoline (\$262.3/m^3), distillate oil (\$238.4/m^3), residual oil (\$164.2/m^3), and kerosene (\$243.4/m^3).

Finally, total annual refinery revenues have been estimated based upon crude capacity utilization of 64 percent[24] and 357 operating days each year. The determination of annual revenues, for both refineries before and after the addition of FCC capacity, is summarized in Tables 9-20 through 9-23. For purpose of price increase estimation, refinery revenues after the installation of additional FCC capacity are of concern. However, in the profitability analysis described in the following section, the increase in revenues made possible by the additional FCC capacity is of interest.

9.2.2.2. Profitability Impact Methodology. In order to estimate the consequences of the full absorption of NSPS control costs, an Internal Rate

Table 9-19. REFINERY PRODUCT YIELDS
(percent)

Product	Small Refinery			Large Refinery		
	24%	40%	56%[a]	30%	40%	50%[a]
Gasoline	48.4	51.1	53.8	49.4	51.1	52.8
Distillate	27.7	26.0	24.3	27.1	26.0	24.9
Residual	14.9	13.9	12.9	14.5	13.9	13.3
Kerosene	9.0	9.0	9.0	9.0	9.0	9.0
Total	100.0	100.0	100.0	100.0	100.0	100.0

[a] Percent of crude throughput processed by FCC.

Table 9-20. REFINERY ANNUAL REVENUE; SMALL REFINERY (8,000 m^3/sd); 64 PERCENT CAPACITY UTILIZATION: BEFORE FCC ADDITION

Product	Total Output[a] (m^3/sd)	Product Yield[b] (percent)	Product Volume (m^3/sd)	Product Price[c] ($/$m^3$)	Product Revenue ($ 1980 IV)
Gasoline	5,120	48.4	2,478	262.3	649,979
Distillate	5,120	27.7	1,418	238.4	338,051
Residual	5,120	14.9	763	164.2	125,285
Kerosene	5,120	9.0	461	243.4	112,207
				Revenue/sd	1,225,522
				x sd/year	357
				Annual Revenue	$437,511,354

[a] 8,000 m^3/sd x 0.64.

[b] Table 9-19.

[c] Reference 23, wholesale prices, November 1980.

Table 9-21. REFINERY ANNUAL REVENUE; SMALL REFINERY (8,000 m^3/sd); 64 PERCENT CAPACITY UTILIZATION: AFTER FCC ADDITION

Product	Total Output[a] (m^3/sd)	Product Yield[b] (percent)	Product Volume (m^3/sd)	Product Price[c] (\$/m^3)	Product Revenue (\$ 1980 IV)
Gasoline	5,120	53.8	2,755	262.3	722,637
Distillate	5,120	24.3	1,244	238.4	296,570
Residual	5,120	12.9	660	164.2	108,372
Kerosene	5,120	9.0	461	243.4	112,207
				Revenue/sd	1,239,786
				x sd/year	357
				Annual Revenue	$442,603,602

[a] 8,000 m^3/sd x 0.64.

[b] Table 9-19.

[c] Reference 23, wholesale prices, November 1980.

Table 9-22. REFINERY ANNUAL REVENUE; LARGE REFINERY (40,000 m^3/sd); 64 PERCENT CAPACITY UTILIZATION: BEFORE FCC ADDITION

Product	Total Output[a] (m^3/sd)	Product Yield[b] (percent)	Product Volume (m^3/sd)	Product Price[c] (\$/m^3)	Product Revenue (\$ 1980 IV)
Gasoline	25,600	49.4	12,646	262.3	3,317,046
Distillate	25,600	27.1	6,938	238.4	1,654,019
Residual	25,600	14.5	3,712	164.2	609,510
Kerosene	25,600	9.0	2,304	243.4	560,794
				Revenue/sd	6,141,369
				x sd/year	357
			Annual Revenue		$2,192,468,733

[a] 40,000 m^3/sd x 0.64.

[b] Table 9-19.

[c] Reference 23, wholesale prices, November 1980.

Table 9-23. REFINERY ANNUAL REVENUE; LARGE REFINERY (40,000 m^3/sd); 64 PERCENT CAPACITY UTILIZATION: AFTER FCC ADDITION

Product	Total Output[a] (m^3/sd)	Product Yield[b] (percent)	Product Volume (m^3/sd)	Product Price[c] (\$/m^3)	Product Revenue (\$ 1980 IV)
Gasoline	25,600	52.8	13,517	262.3	3,545,509
Distillate	25,600	24.9	6,374	238.4	1,519,562
Residual	25,600	13.3	3,405	164.2	559,101
Kerosene	25,600	9.0	2,304	243.4	560,794
				Revenue/sd	6,184,966
				x sd/year	357
				Annual Revenue	$2,208,032,862

[a] 40,000 m^3/sd x 0.64.

[b] Table 9-19.

[c] Reference 23, wholesale prices, November 1980.

of Return (IRR) analysis has been conducted. This type of analysis provides an estimate of an investment's profitability through both the inspection of all variables that influence cash flows over the life of the investment, and the expression of profitability in terms of a single percentage rate or IRR. Analysis of the change in the IRR, caused by the inability to pass-through NSPS control costs, serves as the basis for conclusions with regard to the impact of such costs upon the incentive to construct and operate the refinery units in question. It should be noted that in this application the focus is upon increases and decreases in refinery revenues and costs that are directly attributable to the installation and operation of FCC capacity and the related NSPS control equipment.

In the following discussion, the use of IRR analysis in the estimation of potential profitability impacts is explained. First, all variables that affect the investment decision are presented along with the assumptions made and data sources used in the assignment of values to these variables. This is followed by a sample of the method by which annual cash flows are determined and evaluated to identify the IRR. In the estimation of potential profitability impacts of NSPS controls, several variables have been assembled and evaluated to allow their incorporation into the IRR model. In the descriptions presented below each of these variables is identified and discussed in terms of its use in the model. In addition, sources of data used to quantify each of the variables, are noted.

With regard to the prices of refinery products, those price levels prevailing in November of 1980, including the previously described adjustment for price decontrol, have been used.[22] It has also been assumed that the refinery produces four products; gasoline, distillate oil, residual oil, and kerosene, which in reality account for over 86 percent of the volume produced at domestic refineries.[2] In this analysis the following constant prices have been used; gasoline (\$262.3/m^3), distillate oil (\$238.4/m^3), residual oil (\$164.2/m^3), kerosene (\$243.4/m^3). No inflation adjustments were made.

It is assumed that the refinery has 357 operating days each year, and that the rate of crude capacity utilization is 64 percent.[24]

Crude acquisition costs have been determined according to an average refiner acquisition cost of \$213.2/m^3. This crude price is essentially identical to that reported for January 15, 1982[25].

attributable to price decontrol[22]. Heavier crudes are estimated to be 3.7 percent cheaper than the average quality crudes processed at domestic refineries.[26]

Operating and maintenance costs for additional FCC capacity are \$3.02/m^3 and \$2.86/m^3 for the 2,500 m^3/sd and 8,000 m^3/sd FCC units respectively.[27]. Costs included are materials, labor and maintenance supervision, utilities, indirect costs, and plant overhead.

Concerning depreciation, annual charges have been determined based upon accelerated depreciation over 5 years. The use of a 5-year asset life is in accordance with the Accelerated Cost Recovery System (ACRS) defined by the Economic Recovery Tax Act of 1981.[28] The required capital investment in the FCC and supporting units is \$8,869/m^3/sd based upon 7,949 m^3/sd capacity.[29] Based upon this estimate and a scale-up factor of .85, the small model unit is assumed to require an investment of \$26,373,000, while the large model unit requires \$70,884,000.

With regard to debt terms it has been assumed that part of the investment is financed through debt and will be done so at a real rate of 10 percent over 10 years. It is assumed that the investment will be financed at 40 percent debt and 60 percent equity as is customary in the refining industry.[30]

Concerning NSPS control costs, such costs have been presented in Chapter 8. However, in order to allow consideration of the tax-reducing effects of interest payments, all capital charges have been separated into their depreciation and interest components.

The Federal tax rate is assumed to be 46 percent, the rate on taxable income on earnings in excess of \$100,000 annually.[31] It is also assumed that the investment tax credit is taken on new investments. The credit cannot exceed 10 percent of the investment and cannot be carried forward more than fifteen years.[32]

Working capital or funds required to finance accounts receivable and inventories are included in the IRR model as 10 percent of the additional sales created by the new investment.[33] In the model it is assumed that working capital is financed from equity and is recovered at the end of the last year that the new unit is operated.

Since the investment time horizon in the IRR model is 10 years, and since the FCC unit has a depreciable life of 5 years, the salvage value of the unit after 10 years is assumed to be zero.

Several situations have been evaluated in order to estimate levels of profitability for FCC additions made under various circumstances such as, small vs. large units and refineries, quality of crude oil used, and level of NSPS control. The example presented below pertains to a small FCC unit (2,500 m^3/sd), added to a small (8,000 m^3/sd) refinery, and subject to control costs specific to Case 2, Regulatory Alternative II (Table 8-5).

Since the new unit is installed at an operating refinery, the profitability of the unit is evaluated through the inspection of changes in refinery revenues and costs. Consequently, all dollar amounts discussed below, are representative of increases or decreases in cost, revenue, tax and cash flow totals that would accrue at the refinery in the absence of the FCC addition. For this reason, the profitability of the new unit can be evaluated without the need to estimate the profitability of the refinery before the FCC addition.

The cash flows specific to the investment to be discussed are summarized in Table 9-24. The line-by-line determination of annual cash flows is explained below.

- Row 1, Revenue, represents the increase in refinery revenues (sales) made possible through the addition of FCC capacity. The annual revenue addition of $5,092,000 is the difference between revenues before the FCC addition $437,511,000 (Table 9-20) and after the FCC addition $442,603,000 (Table 9-21).
- Row 2, Crude Acquisition Costs, represents the cost reduction made possible through the ability to process greater amounts of heavier, less expensive crudes. As noted in the previous section, heavier crudes are estimated to be 3.7 percent cheaper than average quality crudes. Since the refinery has crude capacity of 8,000 m^3/sd, and is operating at 64 percent of capacity, and since the FCC addition has capacity of 2,500 m^3/sd, it is estimated that 48.8 percent (i.e. 2,500 ÷ (8,000 x 0.64)) of the total crude processed, can be replaced by heavier crude. Total cost reduction is therefore 1.8056 percent (i.e. 48.8 x 0.037). Since annual crude costs before the addition are $389,695,000

Table 9-24. EXAMPLE: CASH FLOW ANALYSIS; CASE 2, REGULATORY ALTERNATIVE II

($1,000 1980 IV)

	Year									
	82	83	84	85	86	87	88	89	90	91
1. REVENUE	5,092	5,092	5,092	5,092	5,092	5,092	5,092	5,092	5,092	5,092
2. Crude Acquisition Cost	-7,036	-7,036	-7,036	-7,036	-7,036	-7,036	-7,036	-7,036	-7,036	-7,036
3. Operating and Maintenance	2,695	2,695	2,695	2,695	2,695	2,695	2,695	2,695	2,695	2,695
4. Depreciation	3,956	5,802	5,538	5,538	5,538	-	-	-	-	-
5. Interest	1,055	989	916	836	748	651	544	427	298	156
6. Total Cost (2 +...5)	670	2,450	2,113	2,033	1,945	-3,690	-3,797	-3,914	-4,043	-4,185
7. Operating and Maintenance: NSPS	334	334	334	334	334	334	334	334	334	334
8. Depreciation: NSPS	480	704	672	672	672	-	-	-	-	-
9. Interest: NSPS	320	300	278	254	227	197	165	130	90	47
10. Total Cost: NSPS (7+...9)	1,134	1,338	1,284	1,260	1,233	531	499	464	424	381
11. TOTAL COST (6+10)	1,804	3,788	3,397	3,293	3,178	-3,159	-3,298	-3,450	-3,619	-3,804
12. EARNINGS BEFORE TAX (1-11)	3,288	1,304	1,695	1,799	1,914	8,251	8,390	8,542	8,711	8,896
13. Tax Liability (12 x 0.46)	1,512	600	780	828	880	3,795	3,859	3,929	4,007	4,092
14. Investment Tax Credit	1,364	543	704	346	-	-	-	-	-	-
15. TOTAL TAX (13-14)	148	57	76	482	880	3,795	3,859	3,929	4,007	4,092
16. EARNINGS AFTER TAX (12-15)	3,140	1,247	1,619	1,317	1,034	4,456	4,531	4,613	4,704	4,804
17. Depreciation	3,956	5,802	5,538	5,538	5,538	-	-	-	-	-
18. Depreciation: NSPS	480	704	672	672	672	-	-	-	-	-
19. Working Capital Recovery	-	-	-	-	-	-	-	-	-	509
20. Salvage Value	-	-	-	-	-	-	-	-	-	-
21. Principal Repayment	662	728	801	881	969	1,066	1,173	1,290	1,419	1,561
22. Principal Repayment: NSPS	201	221	243	267	294	323	356	391	430	473
23. NET CASH FLOW (16+17+18+19+ 20-21-22)	6,713	6,804	6,785	6,379	5,981	3,067	3,002	2,932	2,855	3,279
24. Discount Factor	0.742	0.551	0.409	0.304	0.226	0.167	0.124	0.092	0.069	0.051
25. Discounted Cash Flow (23 x 24)	4,981	3,749	2,775	1,939	1,352	512	372	270	197	167

(i.e. $213.2 x 8,000 x 0.64 x 357) the estimated potential reduction in crude acquisition costs is $7,036,000 (i.e.$389,695,000 x 0.018056).

- Row 3, Operating and Maintenance expenses are based upon FCC operating and maintenance costs of $\$3.02/m^3$. Annual operating and maintenance cost increases are therefore $2,695,000 (i.e. $3.02 x 2,500 x 357).
- Row 4, Depreciation, is based upon the accelerated (ACRS) depreciation of a capital expenditure of $26,373,000 over 5 years. ACRS allows annual depreciation charges to be 15 percent for the first year, 22 percent for the second year, and 21 percent for the third, fourth, and fifth years.
- Row 5, Interest, for each year is based upon the interest/principal repayment schedule for a loan of $10,549,000 (i.e. $26,373,000 x 0.4 (debt portion)) at 10 percent for 10 years.
- Row 6, Total Cost, is the sum of cost increases related to the FCC addition and indicated in rows 2 through 5.
- Row 7, Operating and Maintenance: NSPS, Costs are taken from Table 8-5. Operating and maintenance costs attributable to NSPS are total net annual costs ($860,000) less the capital recovery costs ($526,000) which are accounted for separately in rows 8 and 9. Such costs are therefore $334,000 in each year.
- Row 8, Depreciation: NSPS, is based upon the accelerated (ACRS) depreciation of a capital expenditure of $3,200,000.
- Row 9, Interest: NSPS, for each year is determined through the calculation of the interest/principal repayment schedule for a loan of $3,200,000 at real rate of 10 percent for 10 years.
- Row 10, Total Cost: NSPS, is the sum of all costs related to NSPS controls and indicated in rows 7 through 9.
- Row 11, Total Cost, is the total of all costs related to both the FCC unit and the NSPS control equipment. It is therefore representative of the net change in total refinery costs that are attributable to the purchase, installation and operation of the new FCC unit and its related NSPS control equipment.
- Row 12, Earnings Before Tax, is obtained by subtracting the change in refinery costs (row 11) from the increase in refinery

revenues (row 1) to determine the net change in pre-tax earnings attributable to the controlled FCC addition.

- Row 13, Tax Liability, is calculated based upon a marginal tax rate of 46 percent.
- Row 14, Investment Tax Credit, is determined by allowing a credit of 10 percent of the added investment. A single year's credit should not exceed the first $25,000 in tax liability plus 90 percent of liability over $25,000. Since the situation described in Table 9-24 requires a total investment of $29,573,000 (i.e., $26,373,000 for the FCC unit and $3,200,000 for NSPS control equipment), the total investment tax credit available is $2,957,000.
- Row 15, Total Tax, is each year's tax liability less that year's investment tax credit.
- Row 16, Earnings After Tax, is the total of annual earnings after all taxes have been paid. Earnings after tax is one component of annual net cash flow.
- Rows 17 and 18, Depreciation, entail the "adding back" of depreciation expenses for both the FCC unit and NSPS control equipment. Depreciation is added back since it is a non-cash expense and is included as a cost simply to allow the determination of annual tax liability.
- Row 19, Working Capital Recovery, must be added to the final year's cash flow since those funds that had been required to finance accounts receivable and inventories will no longer be needed when the unit is sold after the end of the tenth year. The amount of working capital recovered is $509,000 since this amount was financed by equity in the first year.
- Row 20, The Salvage Value of the fully depreciated unit is assumed to be zero because it is unlikely that the unit will be liquidated.
- Rows 21 and 22, Principal Repayment, are deducted from the annual cash flows since they are not tax deductible expenses.
- Row 23, Net Cash Flow, is a summary of all cash flows (i.e. earnings after tax, depreciation, working capital recovery, and salvage value) and deduction of principal repayments.

Finally Rows 24 and 25 are presented to illustrate the mechanics of the determination of the IRR. The IRR for uneven annual cash flows can only be calculated through an iterative procedure that gradually identifies the discount factor (or IRR) that equates the sum of the discounted cash flows with the original equity investment. The IRR is therefore an indication of the profitability of an investment over its entire life.

In the example presented the IRR is 34.7 percent. This is so since when each year's discount factor (Row 24), which is determined by;

$$\text{Discount Factor; Year } n = \frac{1}{(1.347)^n}$$

is applied to the annual net cash flows (Row 23), the sum of the discounted cash flows ($16.3 million) is equal to the original equity investment made at the beginning of 1982. In this case the equity investment is the sum of $15.8 million (equity portion of total investment) and $0.5 million in working capital.

A procedure identical to that described above has been performed for 26 situations representing various assumptions related to model unit size, feedstock sulfur levels, venturi system used (i.e., high energy vs. jet ejector) and NSPS regulatory alternative. The results of that analysis are presented and discusssed in Section 9.2.3.2.

9.2.3 Economic Impacts

9.2.3.1 Price Impacts. As noted in Section 9.2.2.1 maximum potential price increases have been estimated through the expression of annualized control costs as a percentage of the annual revenues of the refineries at which new FCC units are likely to be constructed and modified or reconstructed. The results of that procedure are summarized in Tables 9-25 and 9-26 for small and large units, respectively.

According to the results presented in the tables noted above, maximum price increases for refined petroleum products are relatively small and and thus the demand for such products should be unaffected. It is most likely therefore that the profitability of refining activities will not be impacted by the costs related to this NSPS.

The price increases noted above are in all cases less than 0.4 percent, and are judged to be small in light of volatile price movements in the refined

Table 9-25. PERCENT PRICE INCREASES BY REGULATORY ALTERNATIVE: SMALL (2,500 m^3/sd) MODEL UNIT

	Regulatory Alternative		
	II	III	IV
High Energy Venturi			
0.3 Percent Sulfur			
Caustic Soda	0.00	0.15	0.16
Soda Ash	0.00	0.15	0.15
1.5 Percent Sulfur			
Caustic Soda	0.23	0.23	0.24
Soda Ash	0.19	0.20	0.20
3.5 Percent Sulfur			
Caustic Soda	0.33	0.34	0.35
Soda Ash	0.26	0.26	0.27
Jet Ejector Venturi			
1.5 Percent Sulfur			
Caustic Soda	0.34	0.35	0.36
Soda Ash	0.31	0.31	0.32

Table 9-26. PERCENT PRICE INCREASES BY REGULATORY ALTERNATIVE: LARGE (8,000 m^3/sd) MODEL UNIT

	Regulatory Alternative		
	II	III	IV
High Energy Venturi			
0.3 Percent Sulfur			
Caustic Soda	0.00	0.06	0.06
Soda Ash	0.00	0.05	0.06
1.5 Percent Sulfur			
Caustic Soda	0.11	0.11	0.12
Soda Ash	0.08	0.09	0.09
3.5 Percent Sulfur			
Caustic Soda	0.17	0.18	0.18
Soda Ash	0.13	0.13	0.13
Jet Ejector Venturi			
1.5 Percent Sulfur			
Caustic Soda	0.16	0.17	0.17
Soda Ash	0.14	0.14	0.15

products market. For example, escalating crude prices alone have caused the wholesale prices of motor gasoline, distillate oil, and residual fuel oil to increase 28.7, 20.1, and 32.5 percent respectively from November 1979 to November 1980. Furthermore the previously discussed decontrol of domestic crude is expected to increase average crude prices by an additional 13 percent, an increase that industry analysts agree will be passed-on to consumers.[22] These developments along with the generally low elasticity of demand for petroleum products (see Table 9-9) indicate that the NSPS related control costs should be ultimately paid by the consumer in the form of slight product price increases.

9.2.3.2 Profitability Impacts. As noted in the previous section it is most likely that the economic impacts of this standard will be expressed in terms of product price increases, and thus the profitability of both new and modified/reconstructed units should be unaffected. However, estimates of new unit profitability reductions have been made in order to assess the unlikely event that small product price increases are resisted by consumers.

As explained in Section 9.2.2.2, the IRR method allows the expression of the profitability of a multi-year investment as a single percentage rate. Therefore the comparison of those rates, or Internal Rates of Return (IRRs) both before and after NSPS control, provides an indication of the extent to which profitability may be reduced if related cost increases must be absorbed by refiners.

Because the costs of NSPS vary according to both the sulfur content of FCC feedstocks and the use of caustic soda vs. soda ash in the control process, estimates of profitability reductions also vary. For this reason profitability impacts in terms of IRRs after NSPS have been estimated as ranges, where the upper limits are defined according to the use of 1.5 percent sulfur feedstock and soda ash, while the lower limits are estimated based upon high (3.5%) sulfur feedstocks and the more expensive caustic soda.

Table 9-27 summarizes the ranges of profitability estimated for additional FCC capacity. The table notes both the uncontrolled or baseline IRR for each unit as well as IRRs for each regulatory alternative.

The extremes of profitability reduction noted in Table 9-27 would not, if actually incurred, reduce the profitability of new FCC operations to the point where planned investments would be postponed. This is so since all situations allow the possibility of a return greater than 18 percent which

Table 9-27. INTERNAL RATES OF RETURN REFINERY UTILIZATION RATE = 64%

Regulatory Alternative	Small (2,500 m^3/sd) Model Unit Low[a]	Small (2,500 m^3/sd) Model Unit High[b]	Large (8,000 m^3/sd) Model Unit Low[a]	Large (8,000 m^3/sd) Model Unit High[b]
No Control[c]	37.7		44.9	
High Energy Venturi				
Reg. Alt. II	31.3	34.7	39.6	42.8
Reg. Alt. III	31.1	34.5	39.4	42.7
Reg. Alt. IV	30.9	34.5	39.3	42.6
Jet Ejector Venturi				
Reg. Alt. II	31.1	31.9	40.4	41.1
Reg. Alt. III	30.8	31.8	40.2	41.0
Reg. Alt. IV	30.6	31.7	40.0	40.9

[a] Assumes caustic soda and 3.5% sulfur feedstock with high energy venturi, and 1.5% sulfur feedstock with jet ejector venturi.

[b] Assumes soda ash and 1.5% sulfur feedstock for both venturi systems.

[c] Without the use of Accelerated Cost Recovery, No Control IRR's are 31.0 and 37.3 percent for the small and large units respectively.

has been estimated as the average cost of equity to those firms that may be affected by NSPS. The cost of equity noted above has been estimated based upon the reported stock prices of and earnings per share of 31 integrated oil companies and independent refiners for 1979.[35]

9.2.3.3 Capital Availability. Compliance with each of the regulatory alternatives requires that additional capital expenditures be made for the purchase and installation of control equipment. Comparison of the capital control costs (Tables 8-1 and 8-10) to the FCC unit capital costs noted in Section 9.2.2.2 indicates that the capital requirements of the small unit could increase 12.1 and 17.8 percent under the high energy and jet ejector venturi systems respectively. For the larger unit the percentage increases are 7.6 and 11.6 for the same systems.

While the capital requirements noted above will cause affected refiners to seek additional financing, it is not expected that capital availability difficulties will be encountered. This conclusion is based upon two observations.

First, the IRR analysis described in previous sections has implicitly indicated that even with the addition of non-productive control equipment the profitability of the investment is maintained. More specifically, since the control equipment was assumed to have been financed from debt the payback of that debt is assured. This observation is evidence to those who would provide debt financing that the debt can be repayed.

Second, the overall trends in earnings and cash generation exhibited by the industry have led to steadily decreasing debt-to-equity ratios. Such ratios are in many cases less than 30 percent,[36] an indication that many companies may finance the control expenditures noted above, as well as other much larger expenditures, without the use of outside funds.

9.3 SOCIOECONOMIC AND INFLATIONARY IMPACTS

Section 9.2 has described the potential economic impacts of NSPS upon the petroleum refining segment of the economy. In this section broader economic impacts are examined including inflationary, employment, balance of trade, and small business impacts. In addition the significance of the impacts of the regulatory alternatives from the point-of-view of Executive Order 12291 is assessed.

9.3.1 Executive Order 12291

According to the directives of Executive Order 12291 "major rules" are those that are projected to have any of the following impacts:

- an annual effect on the economy of $100 million or more,
- a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions, or
- significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of the United States-based enterprises to compete with foreign-based enterprises in domestic or export markets.

In each of the following sections these criteria are examined in relation to the proposed standard.

9.3.1.1 Fifth-Year Annualized Costs. Table 8-13 provides a summary of the determination of the fifth-year annualized costs of this standard. As indicated, such costs are calculated through the multiplication of the annualized costs related to each FCC unit type and sulfur level, by the number of each unit expected to be constructed over the five-year period. Fifth-year costs are therefore estimated as $32.1, $35.2, and $36.7 million for Regulatory Alternatives II, III, and IV respectively.

9.3.1.2 Inflationary Impacts. As noted in Section 9.2.3.1 potential price increases for refined petroleum products are estimated to be less than 0.4 percent. For reasons detailed in that section price increases are most likely to be lower than those indicated as refiners employ less costly control inputs. Refined product price increases of the magnitude estimated are expected to cause virtually no increase in the rate of inflation.

9.3.1.3 Employment Impacts. As described in Section 9.2 the regulatory alternatives are not expected to have any impact upon the demand for the products of, or profitability of, new FCC units. For this reason no impacts upon refinery employment are anticipated.

9.3.1.4 Balance of Trade Impacts. As noted in Sections 9.1.2.4 and 9.1.2.5, very small portions of the total domestic production of refined petroleum products are traded internationally. For this reason, along with the very low price impacts estimated, no potential for impact upon the United States balance of trade is indicated.

9.3.2 Small Business Impacts - Regulatory Flexibility

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. The following discussion is intended to certify that this regulation will not have a significant economic impact on a substantial number of small businesses, thus eliminating the need to perform a Regulatory Flexibility Analysis.

The conclusions noted above have been based upon the definition and consideration of three factors:

- the maximum size of a small business;
- the number of small businesses affected; and
- the expected economic impacts.

With regard to size, the Small Business Administration (SBA) has defined small petroleum refineries as those that employ fewer than 1,500 persons. This total, which includes subsidiaries and other affiliated operations, has been specified by SBA (13 CFR, Part 121) for the purpose of its various loan and assistance programs.

Concerning the number of small businesses affected, if the prospective affected facilities were distributed proportionately between large and small refiners, two or three units would be built by the small refiners. However, due to the discontinuance of the entitlements program, very little construction is anticipated at the small refineries. Thus the percentage of small refining businesses affected will be well below the level of concern.

In addition, the economic impacts are expected to be minor even for the small refiners. As noted in the previous sections, the cost of this NSPS should be capable of being included in the prices of refined petroleum products, and in all cases price increases are less than 0.4 percent. Therefore, because the standard does not affect a substantial number of small businesses and will not entail significant economic impacts, a Regulatory Flexibility Analysis has not been conducted.

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*References can be located in Docket Number A-79-09 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

APPENDIX A

APPENDIX A. EVOLUTION OF THE PROPOSED STANDARDS

A.1 INTRODUCTION

The Clean Air Act Amendments of 1970 strengthened the Air Quality Act of 1967 by including authority to promulgate standards of performance for major new sources (Section 111) and to promulgate national emission standards for existing sources of hazardous pollutants (Section 112). During the 1977 hearings on the Clean Air Act, Congress received testimony on the need for more rapid standard development. There was concern that not all sources which had the potential to endanger public health or welfare were controlled. These concerns were reflected in the Clean Air Act Amendments of 1977. The Amendments require promulgation of the new source performance standards (NSPS) on a greatly accelerated schedule.

As provided for under Section 111 of the Clean Air Act, the standard setting mechanism also includes a 4-year review of all promulgated standards. As a result of this review, FCC unit regenerator sulfur oxides emissions were identified as a pollutant to be studied, to determine the need for an NSPS for new and modified facilities. NSPS development for the control of sulfur oxides emissions from FCC unit regenerators began in March 1980.

Information was gathered through plant visits to petroleum refineries, Section 114 information request letters to oil companies, and telephone contacts to industry representatives, consultants, and equipment manufacturers. In addition, a literature survey, including examination of emission test results, was conducted. The major events relating to this effort are listed chronologically below.

A.2 CHRONOLOGY

The following chronology lists important events that occurred during the development of the background information document for the fluid catalytic cracking unit regenerator NSPS.

CHRONOLOGY

Date	Activity
3/8/74	Particulate and carbon monoxide NSPS promulgated for fluid catalytic cracking unit regenerators (39 FR 9315).
10/22/79	The results of the 4-year review of standards and EPA's intent to undertake the development of an NSPS to limit SO_2 emissions from fluid catalytic cracking unit catalyst regenerators announced in the Federal Register (44 FR 60759).
3/5/80	Formal kickoff meeting held between EPA and the contractor, Pacific Environmental Services, Inc. (PES).
4/1/80	Initial meeting held with representatives of Amoco to establish contact among the organizations and provide background information on current catalyst technology, hydrodesulfurization, and scrubbers.
4/2/80	Initial meeting held with representatives of ARCO to establish contact among the organizations and provide background information on current catalyst technology, hydrodesulfurization, and scrubbers.
4/3/80	Initial meeting held with representatives of Chevron to establish contact among the organizations and provide background information on current catalyst technology, hydrodesulfurization, and scrubbers.
[illegible]/3/80	Meeting held with Bay Area Air Quality Management District (California) to discuss their SO_2 emission limit for FCCU's.
5/21/80	A visit was made to the New Jersey Department of Environmental Protection (NJDEP) to acquire information on Exxon FCCU in Linden, New Jersey.
5/22/80	A visit was made to the Texas Air Control Board (TACB) to obtain emission data.

CHRONOLOGY (Continued)

Date	Activity
6/18/80	Meeting held with the American Petroleum Institute (API) Stationary Source Advisory Committee to establish protocol and acquaint the Stationary Source Advisory Committee with the FCCU new source performance standard study.
7/23/80	An initial meeting was held with representatives of Shell Oil Company to discuss some of the control capabilities of hydrodesulfurization.
7/23/80	An initial meeting was held with representatives of Pullman Kellogg to discuss residual cracking activities and typical FCC maintenance procedures.
7/24/80	A plant visit was made to the Exxon Company U.S.A. refinery in Baton Rouge, Louisiana, to view the operation of the jet-ejector scrubber and to assess the potential for emissions testing.
8/13/80	A plant visit was made to the Oklahoma Refining Company refinery in Oklahoma City, Oklahoma, to obtain information on hydrodesulfurization and small refinery operations.
8/14/80	A plant visit was made to the Conoco Oil Refinery in Ponca City, Oklahoma, to obtain information on hydrodesulfurization and small refinery operations.
9/24/80	A plant visit was made to the Marathon Oil Company Refinery in Garyville, Louisiana, to gather background information on the control of FCCU regenerator sulfur oxides emissions with wet gas scrubbers.
10/28-31/80	PES staff member attended the EPA symposium on Flue Gas Desulfurization.
12/8/80	Section 114 letter sent to the Marathon Oil Company Refinery in Garyville, Louisiana, on FCCU scrubber performance.

CHRONOLOGY (Continued)

Dates	Activities
2/19-20/81	Section 114 letters sent to Amoco, ARCO, Rock Island Refinery, Phillips Petroleum, Chevron, Texas City Refining, and Ashland on FCCU modifications.
3/18/81	Received Rock Island Refining Corporation's response to the Section 114 letter.
3/20/81	Received Marathon Oil Company's response to the Section 114 letter.
3/24/81	Received Chevron's response to the Section 114 letter.
3/26/81	Draft BID Chapters 3-6 mailed to industry, environmental organizations, and State agencies for comments.
4/3/81	Received ARCO's response to the Section 114 letter.
4/13-5/29/81	Received comments of draft BID Chapters 3-6 from American Petroleum Institute, Chevron Research Company, Davy McKee Corporation, Mobil Oil, Amoco Oil, and M.W. Kellogg.
5/4-6/2/81	Source testing at the Marathon Oil Company Refinery in Garyville, Louisiana.
5/22/81	Section 114 letter sent to Chevron for information on sulfur oxides reduction catalyst technology.
5/27/81	Received Ashland Petroleum Company's response to the Section 114 letter.
7/6/81	Received Chevron's response to the Section 114 letter on sulfur oxides reduction catalyst technology.
8/24/81	Received response to Section 114 letter from Texas City Refining.
8/27/81	Meeting held with API to discuss project status and baseline nitrogen oxides emissions assessment program.

CHRONOLOGY (Continued)

Dates	Activities
10/7/81	Section 114 letter on baseline NO_x emissions from FCCU regenerators and existing data on SO_x and NO_x emissions from sulfur oxides reduction catalysts sent to Chevron.
10/15/81	Section 114 letter on baseline NO_x emissions from FCCU regenerators and existing data on SO_x and NO_x emissions from sulfur oxides reduction catalysts sent to Southwestern Refining Company, Atlantic Richfield Company, Phillips Petroleum Company, Standard Oil of Indiana, Texaco, Mobil Oil Corporation, Gulf Oil Company, and Union Oil of California.
10/27/81	NAPCTAC package distributed to Federal agencies, industry, and public interest groups.
10/28/81	Notification of NAPCTAC meeting sent to the Philadelphia Department of Public Health and Colorado Department of Health.
11/5/81	Notice of NAPCTAC meeting published in Federal Register.
11/6/81	Letter sent to Davison Chemical Division, W.R. Grace and Company requesting existing commercial and pilot plant test data on sulfur oxides reduction catalysts.
11/10/81	Meeting held with API to discuss the baseline NO_x emissions assessment program and industry responses to the Section 114 letters requesting NO_x test data.
11/10/81	Letter sent to Englehardt Corporation requesting existing commercial and pilot plant test data on sulfur oxides reduction catalysts.
11/16/81	Letter sent to Filtrol Corporation requesting existing commercial and pilot plant test data on sulfur oxides reduction catalysts.

CHRONOLOGY (Continued)

Dates	Activities
11/23/81	Received API response to EPA information request for FCCU NO_x emissions data.
11/24/81	Received Texaco U.S.A. comments regarding EPA request for NO_x emissions testing.
12/1/81	NAPCTAC meeting held at the Royal Villa Hotel in Raleigh, North Carolina.
12/1/81	Received ARCO comments regarding EPA information request for FCCU NO_x emission data and the API alternative plan.
12/8/81	Received Mobil Oil Corporation's comments regarding EPA information request for FCCU NO_x emission data.
12/9/81	Received Southwestern Refining Company comments regarding EPA request for FCCU NO_x emission data and the API alternative plan.
12/9/81	Received Standard Oil Company comments regarding EPA request for FCCU NO_x emission data and the API alternative plan.
12/14/81	Received FMC Corporation response to EPA request for dual alkali capital and operating costs.
12/14/81	Letter sent to Exxon Research and Engineering Company requesting test data on guarantee test for Exxon scrubber on FCCU at Southwestern Refining Company's refinery.
12/14/81	Letter sent to Texas Air Control Board requesting results of FCCU scrubber compliance test conducted at Southwestern Refining Company's refinery.
12/15/81	Received Mobil FCCU NO_x emissions test data.
12/16/81	Response to API's alternative plan to obtain existing FCCU NO_x emissions test data prior to initiating additional testing sent out.

CHRONOLOGY (Continued)

Dates	Activities
12/17/81	Received ARCO comments on 10/23/81 draft preamble, regulation, and BID.
12/18/81	Received Texaco U.S.A. comments on 10/23/81 draft preamble, regulation, and BID:
12/22/81	Received Phillips Petroleum Company comments on 10/23/81 draft preamble, regulation, and BID.
12/22/81	Letter sent to Catalyst Recovery, Inc., requesting existing test data on the effects of sulfur oxides reduction catalysts on SO_x and NO_x emissions.
12/29/81	Received Gulf Oil Company response to EPA information request for FCCU NO_x emission data.
1/05/82	Received Texaco U.S.A. response to EPA information request for FCCU NO_x emission data.
1/13/82	Received Chevron U.S.A. summary of FCCU NO_x emission data.
1/13/82	Received Phillips Petroleum Company FCCU regenerator emission test data.
1/15/82	Received Standard Oil Company response to EPA information request for FCCU NO_x emission data.
1/22/82	Received from Texas Air Control Board the results of a compliance test conducted on the Southwestern Refining Company FCCU scrubber.
1/27/82	Letter sent to Davy McKee Corporation requesting review and comments on cost and environmental impact analysis associated with the Wellman-Lord FGD process.
1/29/82	Letter to FMC Corporation requesting review and comments on cost and environmental impact analysis associated with dual alkali scrubbing system.

CHRONOLOGY (Continued)

Dates	Activities
2/04/82	Letter sent to Morrison-Knudsen requesting review and comments on cost and environmental impact analysis associated with citrate FGD process.
2/04/82	Letter sent to U.S. Bureau of Mines requesting review and comments on cost and environmental impact analysis associated with citrate FGD process.
2/04/82	Letter sent to Wheelabrator-Frye, Inc., requesting review and comments on cost and environmental impact analysis associated with spray drying FGD.
2/11/82	Received Mobil Oil Company comments on draft preamble, regulation, and BID for FCCU regenerator SO_x emissions.
2/11/82	Received ARCO resubmission of NO_x emissions data from three ARCO FCC units.
2/12/82	Received Wheelabrator-Frye information on spray drying capital and operating cost parameters for FCCU applications.
2/17/82	Received API-solicited refinery NO_x emissions test data.
2/19/82	Received additional API-solicited refinery NO_x emissions test data.
2/22/82	Received from Exxon Research and Engineering Company results of guarantee tests conducted on 5/6/81 at the FCCU scrubber at Southwestern Refining Company.
2/24/82	Received Davy McKee response to information request concerning cost of Wellman-Lord SO_2 recovery process.
2/24/82	Received Mikropul Corporation response to telecon request for spray drying costs for FCC units.

CHRONOLOGY (Concluded)

Dates	Activities
2/25/82	Letter sent to Southwestern Refining Company requesting cost and operational information regarding the wet gas scrubber system.
3/24/82	Letter sent to the American Petroleum Institute stating that SO_x reduction catalysts do not cause significant increases in NO_x emissions and that additional NO_x test data are not necessary.
3/30/82	Received Chevron comments on the 10/23/81 draft preamble, regulation, and BID.
4/30/82	Received Southwestern Refining Company response to cost and operational information request regarding the wet gas scrubber system.
3/24/83	Draft regulatory package sent to the Office of Management and Budget for review, as required under Executive Order 12291 and the Paperwork Reduction Act of 1980.
11/29/83	Sent to OMB revisions to the regulatory package based on comments made by OMB in November.
12/15/83	Regulatory package concurred on by OMB.

APPENDIX B

APPENDIX B

INDEX TO ENVIRONMENTAL CONSIDERATIONS

This appendix consists of a reference system which is cross-indexed with the October 21, 1974, _Federal Register_ (39 FR 37419) containing the Agency guidelines for the preparation of Environmental Impact Statements. This index can be used to identify sections of the document which contain data and information germane to any portion of the _Federal Register_ guidelines.

APPENDIX B

INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document
(1) Background and summary of regulatory alternatives	The regulatory alternatives are summarized in Chapter 1, Section 1.1, page 1-1.
Statutory basis for proposing standards	The statutory basis for the proposed standards is summarized in Chapter 2, Section 2.1, pages 2-1 through 2-4.
Affected industry	A discussion of the industry affected by the regulatory alternatives is presented in Chapter 3, Section 3.1, pages 3-1 through 3-4. Details of the "business/economic" nature of the industry are presented in Chapter 9, pages 9-1 through 9-26.
Affected sources	A description of the activities to be affected by the regulatory alternatives is presented in Chapter 3, Section 3.2, pages 3-4 through 3-14.
Existing regulations at State or local level	A discussion of existing regulations is included in Chapter 3, Section 3.3, pages 3-19 through 3-22.
Availability of control technology	A discussion of available emission control techniques is presented in Chapter 4, pages 4-11 through 4-34.
(2) Environmental, energy, and economic impacts of regulatory alternatives	Various regulatory alternatives are discussed in Chapter 6, Section 6.2, pages 6-3 through 6-10.

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document
Environmental impacts	The environmental impacts of the various regulatory alternatives are presented in Chapter 7, Sections 7.2, 7.3, and 7.4, pages 7-1 through 7-11.
Energy impacts	The energy impacts of the various regulatory alternatives are discussed in Chapter 7, Section 7-5, pages 7-11 through 7-13.
Cost impacts	Cost impacts of the various regulatory alternatives are discussed in Chapter 8, Section 8.1, pages 8-1 through 8-17.
Economic impacts	The economic impacts of the various regulatory alternatives are presented in Chapter 9, Sections 9.2 and 9.3, pages 9-26 through 9-50.

APPENDIX C

EMISSIONS TEST DATA

APPENDIX C

C.1 INTRODUCTION

Emissions source test data from fluid catalytic cracking (FCC) units are used in this document to support the development of baseline emissions, model FCC units, and performance of pollution control equipment. These data and descriptions of the FCC units and control technologies tested are summarized in this appendix. Emission test data were obtained from industry, from State and local pollution control agencies, and from an emission source test conducted by the U.S. Environmental Protection Agency. The sampling and analysis methods used in these source tests are EPA Method 5 for particulate matter, EPA Method 7 for nitrogen oxides, and either EPA Method 6 for sulfur dioxide or EPA Method 8 for sulfur dioxide, sulfur trioxide, and sulfuric acid mist.

A summary of the flue gas scrubber test data presented in detail in this appendix is found in Table C-1. Sulfur oxides reduction catalyst performance data are summarized in Table C-2. These tables, figures, and the summaries of individual flue gas scrubber and sulfur oxides reduction catalyst test reports are located at the end of this appendix. From Table C-1, flue gas scrubbers have demonstrated sulfur dioxide control efficiencies as high as 97 percent. From Table C-2, sulfur dioxide emissions reductions up to 83 percent have been demonstrated.

C.2 FLUE GAS SCRUBBER EMISSIONS TEST DATA

Available FCC unit flue gas scrubber emissions test data consist of 12 source test reports for 4 refineries operating FCC units. Eleven of these tests were conducted to determine compliance or vendor-guaranteed performance; one test was conducted by the U.S. Environmental Protection Agency for this study. All four FCC units are equipped with sodium-based flue gas scrubbers for particulate matter and sulfur oxides emissions control.

C.2.1 Guarantee and Compliance Test Results

Guarantee tests are performed to verify that the flue gas scrubber meets the vendor's guidelines. Compliance tests are performed to determine if the controlled FCC unit emissions are within allowable limitations.

A description of each FCC unit and flue gas scrubber is provided below. FCC unit flue gas scrubber compliance and guarantee test data are also provided, by refinery.

C.2.1.1 Refinery A.[1] Refinery A operates a single FCC unit with a design fresh feed capacity of 11,500 m^3/sd. High temperature regeneration is utilized for complete carbon monoxide combustion in the regenerator. The FCC unit processes a 0.2 to 0.3 weight percent sulfur feedstock obtained from a hydrotreated heavy gas oil cut from the atmospheric distillation tower.

The flue gases from the FCC unit regenerator pass through two heat recovery devices which cool the gases to approximately 150°C. From these heat recovery devices, the flue gases enter the high energy venturi scrubber. The scrubber consists of four venturis mounted upon a single separator vessel. The flue gases mix with a sodium alkali-based scrubbing liquor within the venturis. As a result of this mixing and the reaction of the sulfur oxides with the scrubbing liquor, both sulfur oxides and catalyst fines (as particulate matter) are removed from the flue gases. The flue gases and scrubbing liquor pass into the separator vessel. Here, entrained scrubbing liquor is separated from the flue gases. The scrubbed flue gases are then vented to atmosphere. Additional alkali is added to the scrubbing liquor from the separator vessel and the liquor is recycled to the venturis. A small purge stream removes sodium salts and particulates to a wastewater treatment plant.

High energy venturi scrubber design flue gas inlet pressures vary from 108 to 112 kPa. Typical design liquid-to-gas (L/G) ratios for the high energy venturi scrubber are 0.7 to 4.0 m^3 of scrubbing liquor per 1,000 m^3 of flue gas.[2] The pH of the scrubbing liquor is maintained at 6 to 7 through a 0.004 to 0.006 m^3/min addition of alkali.

A guarantee test[3] and compliance test,[4] performed in April 1980 and September 1980, respectively, are summarized in Tables C-3 and C-4, respectively. From Table C-3, uncontrolled emissions at the scrubber inlet are, on average, 8.1 kg sulfur dioxide/1,000 coke burn-off, 1.9 kg sulfur trioxide/1,000 kg coke burn-off, and 0.2 kg sulfuric acid mist/1,000 kg coke burn-off. Uncontrolled particulate emissions at the scrubber inlet are 4.4 kg/1,000 kg coke burn-off. Controlled sulfur dioxide emissions range from 0.2 to 0.3 kg/1,000 kg coke burn-off, controlled sulfur trioxide emissions vary from 0.02 to 0.03 kg/1,000 kg coke burn-off, and sulfuric acid mist emissions range from 0.07 to 0.1 kg/1,000 kg coke burn-off. Controlled particulate emissions from Tables C-3 and C-4 range from 0.1 to 0.4 kg/1,000 kg coke burn-off. These results show emission reductions of 97.5 percent in sulfur dioxide, 99 percent for sulfur trioxide, 55 percent for sulfuric acid mist, and 95 percent for particulate matter emissions.

C.2.1.2 Refinery B[2]. Refinery B operates two FCC units with a combined fresh feed capacity of approximately 25,400 m^3/sd.[5] The flue gases from the two FCC units are combined in a common duct and routed through a carbon monoxide combustion furnace. Following the carbon monoxide combustion furnace, the gases enter the jet ejector venturi scrubber. The scrubber contains five jet ejector venturis; only four are normally used during operation. The jet ejector consists of a spray nozzle and venturi. The scrubbing liquor, sprayed into the venturi through the nozzle at 513 to 925 kPa,[6] induces a draft, drawing regenerator flue gas into the venturi. Thus, the jet ejector venturi operates with negligible pressure drop. These venturis utilize a sodium-based scrubbing liquor to remove both particulate matter and sulfur oxides from the flue gases. The flue gases flow from the venturis into a separator vessel for demisting then to atmosphere. Additional alkali is added to the scrubbing liquor from the separator vessel and the liquor is recycled back to the scrubbers. A small purge stream removes particulates and sodium salts to a wastewater treatment plant. Three circulating pumps are available to provide scrubbing liquor to the scrubbers. Only one pump is normally run.

The design L/G ratio for jet ejector venturis is typically 6.7 to 13.4 m^3 of scrubbing liquor per 1,000 m^3 of flue gas.[6]

Five FCC unit scrubber emissions source tests were conducted between December 1977 and June 1980 to determine compliance with emission limitations. The results of these tests[7-11] are summarized in Tables C-5 through C-9. From these tables, controlled particulate emissions range from 1.1 to 2.4 kg/1,000 kg coke burn-off; controlled sulfur dioxide emissions range from 0.2 to 3.7 kg/1,000 kg coke burn-off.

C.2.1.3 Refinery C. Refinery C operates two FCC units with a combined fresh feed capacity of approximately 27,000 m^3/sd.[5] These units utilize conventional regeneration and are equipped with carbon monoxide combustion furnaces. The refinery has two jet ejector venturi scrubber systems, one for each FCC unit.[12] The operation of each of these scrubber systems is similar to that described for Refinery B above.

Compliance tests,[13,14] performed in September 1975 for Unit I and April 1976 for Unit II, are summarized in Tables C-10 and C-11, respectively. For Unit I, controlled particulate emissions are about 0.8 kg/1,000 kg coke burn-off. The typical sulfur dioxide content of the flue gas at the scrubber inlet for this unit is 1,010 vppm.[12] No coke burn-off rate was reported. From Table C-10, controlled sulfur dioxide emissions are about 3.1 kg/1,000 kg coke burn-off. Controlled sulfur trioxide emissions are 0.08 kg/1,000 kg coke burn-off. The reported sulfur dioxide control efficiency for the Unit I scrubber is 94 percent.[12] The typical sulfur dioxide content of the flue gas at the scrubber inlet for Unit II is 660 vppm. Again, no coke burn-off rate was reported. From Table C-11, controlled sulfur dioxide emissions are 0.3 kg/1,000 kg coke burn-off, and controlled sulfur trioxide emissions are 0.08 kg/1,000 kg coke burn-off. The reported sulfur dioxide control efficiency for the Unit II scrubber is 94 percent.[12] Controlled particulate emissions for Unit II are 1.2 kg/1,000 kg coke burn-off.

C.2.1.4 Refinery D. Refinery D operates one FCC unit with a fresh feed capacity of 4,450 m^3/sd.[15] The unit utilizes high temperature regeneration and is equipped with a high energy venturi scrubber system.

A compliance test,[16] performed in May 1981, is summarized in Table C-12 and a guarantee test,[17] performed in May 1981, is summarized in Table C-13. For this refinery's FCC unit, controlled particulate emissions are 0.3 to 0.5 kg/1,000 kg coke burn-off. The sulfur dioxide content of the flue gas from the scrubber is 2.3 to 2.8 kg/1,000 kg coke burn-off, and controlled sulfur trioxide emissions are 0.5 kg/1,000 kg coke burn-off. Nitrogen oxides emissions were also tested. The nitrogen oxides content of the flue gas at the scrubber outlet is 168 vppm, or 3.8 kg/1,000 coke burn-off.

C.2.2. EPA-Conducted Source Test Results

The U.S. Environmental Protection Agency conducted two test programs to evaluate the performance of flue gas scrubbers. One test was conducted on a flue gas scrubber controlling sulfur dioxide emissions from an FCC unit. The second test was conducted on a similar scrubber controlling sulfur dioxide emissions from an industrial boiler. The industrial boiler test results are included to illustrate the performance of flue gas scrubbers similar to those used on FCC units on high inlet sulfur dioxide concentrations.

C.2.2.1 Refinery A. A description of the FCC unit operated at Refinery A is provided in Section C.2.1.1. Tests conducted by EPA include 14-day continuous monitoring of sulfur dioxide emissions into and out from the flue gas scrubber and individual tests of sulfur dioxide, sulfur trioxide, sulfates, nitrogen oxides, hydrocarbons, and particulate emissions. Coke burn-off rates were not available for all test parameters measured. Therefore, not all of the test data are reported in terms of coke burn-off. Results of the test program at this refinery are summarized in Table C-14. Continuous monitoring data are illustrated graphically in Figure C-1.[19] Uncontrolled sulfur dioxide emissions ranged from 12.6 to 24.4 kg/1,000 kg coke burn-off, uncontrolled sulfur trioxide emissions ranged from 2.6 to 8.8 vppm, and sulfates emissions ranged from 7.5 to 23.2 vppm. Uncontrolled particulate emissions ranged from 2.9 to 6.4 kg/1,000 kg coke burn-off. Controlled sulfur dioxide emissions range from 0.4 to 4.0 kg/1,000 kg coke burn-off. Sulfur trioxide emissions range from 0.3 to 1.4 and sulfates from 2.5 to 10.8 vppm. Controlled particulate emissions range from 0.2 to 0.9 kg/1,000 kg coke burn-off. Nitrogen oxides emissions at the scrubber outlet averaged 93 vppm (dry) and total C_{1-6} hydrocarbons averaged 22.7 vppm. Scrubber control efficiencies averaged 83 percent for particulates, 93 percent for sulfur dioxide, 84 percent for sulfur trioxide, and 56 percent for sulfates.

C.2.2.2 Industrial Boiler A.[20] Industrial Boiler A is a Babcock and Wilcox pulverized coal-fired unit. The coal fired in the unit is sub-bituminous, with an ash content of 10 percent and a sulfur content between 3.25 and 3.73 percent. The boiler has a maximum steam generation capacity of 150,000 lb/hr. Flue gas from the boiler passes through mechanical collectors and an electrostatic precipitator for particulate matter removal prior to entering the flue gas scrubber.

Results of EPA-conducted 30-day continuous monitoring of sulfur dioxide concentrations in the boiler flue gas entering and exiting the scrubber is shown graphically in Figure C-2. Sulfur dioxide concentrations in the flue gas entering the scrubber ranges from 1,623 to 2,154 vppm dry. Flue gas sulfur dioxide concentrations out from the scrubber range from 21 to 66 vppm dry. The average control efficiency of the scrubber over the 30-day test period is 97.1 percent.

C.3 SULFUR OXIDES REDUCTION CATALYST TEST DATA

Available sulfur oxides reduction catalyst emission test data consist of a source test report for each of two refineries. These tests were conducted by the catalyst developer to evaluate the performance of sulfur oxides reduction catalysts on emissions of sulfur dioxide and sulfur trioxide.

C.3.1 Sulfur Oxides Reduction Catalyst Test Results

C.3.1.1 Refinery E.[21] Refinery E operates a single FCC unit with a fresh feed capacity of approximately 3,500 m^3/sd. The FCC unit is operated in a complete carbon monoxide combustion mode. The FCC feedstock is a 1 weight percent sulfur vacuum gas oil derived from Sumatra and Alaska North Slope crudes. The sulfur oxides reduction catalyst works by transferring sulfur oxides, formed in the regenerator, back to the reactor. Within the reactor, the sulfur oxides are reduced to hydrogen sulfide. The hydrogen sulfide is removed with the FCC unit products and is ultimately processed in the refinery sulfur plant.

For this test program, the sulfur oxides reduction catalyst was gradually added to represent approximately 10 percent of the total FCC unit catalyst inventory. The sulfur oxides reduction catalyst was maintained at 10 percent of the inventory during steady state by addition to replace reduction catalyst lost due to normal attrition. At the completion of the test, the addition of sulfur oxides reduction catalyst to the FCC unit catalyst inventory was stopped. Sulfur oxides emissions gradually increased as the amount of sulfur oxides reducion catalyst in the FCC unit catalyst inventory decreased due to normal attrition. Testing was conducted prior to the addition of the reduction catalyst, during steady state when the reduction catalyst represented 10 percent of the FCC unit catalyst inventory, and again several weeks after reduction catalyst addition has ceased.

The sulfur oxides reduction catalyst test for Refinery E is summarized in Table C-15. Sulfur oxides emissions dropped from 12.2 to 2.5 kg/1,000 kg coke burn-off after addition of the sulfur oxides reduction catalyst to the circulatory catalyst inventory. Nitric oxide emissions increased from 110 to 700 vppm after addition of the catalyst.

C.3.1.2 Refinery F.[21] Like Refinery E, Refinery F operates a single FCC unit with a fresh feed capacity of approximately 3,500 m^3/sd. The FCC unit operates in the complete carbon monoxide combustion mode, and the feedstock is a 1 weight percent sulfur vacuum gas oil derived from two Texas crudes.

Sulfur oxides reduction catalysts were added as described above for Refinery E. The test results for Refinery F are summarized in Table C-16. Sulfur oxides emissions decreased from 9.9 to between 3.4 to 5.0 kg/1,000 kg coke burn-off after catalyst addition. Nitrogen oxides emissions increased from about 710 to 1,100 to 1,300 vppm.

Table C-1. SUMMARY OF SULFUR OXIDES EMISSIONS TEST DATA FOR FLUE GAS SCRUBBERS

Application	Feed Sulfur Content (wt.% of fresh feed)	Sulfur Oxides Loadings (kg SO_x as SO_2/1,000 kg coke burn-off)		
		Scrubber Inlet	Scrubber Outlet	% Reduction
Refinery A	0.2-0.3	9.8	0.3	97
	0.32-0.60	13.7	1.0	93
Refinery B	N/A[a]	N/A	N/A[b]	N/A
	N/A	N/A	1.5*	N/A
	N/A	N/A	3.7*	N/A
	N/A	N/A	3.7*	N/A
	N/A	N/A	0.2*	N/A
Refinery C	N/A	N/A	3.2	N/A
	N/A	N/A	0.7	N/A
Refinery D	N/A	N/A	0.1	N/A
	0.26	5.1*	0.3*	95
Industrial Boiler A	N/A[c]	N/A[d]	N/A[e]	97.1

[a] Not available.

[b] Reported as 55.2 vppm wet only.

[c] Coal fired boiler. Coal sulfur content ranges from 3.25 - 3.73 weight percent.

[d] Reported as 1,800 vppm dry only.

[e] Reported as 46 vppm dry only.

*Calculated from test results. Emissions represent SO_2 only.

Table C-2. SUMMARY OF SULFUR OXIDES EMISSIONS TEST DATA FOR SULFUR OXIDES REDUCTION CATALYSTS

Refinery	Feed Sulfur Content (wt.% of fresh feed)	Sulfur Dioxide Loadings (kg SO_x as SO_2/1,000 kg coke burn-off)		
		Before catalyst addition	With catalyst in place	% Reduction
E	0.99 - 1.07	12.2	2.5	80
F	1.00 - 1.37	9.9	3.4	66

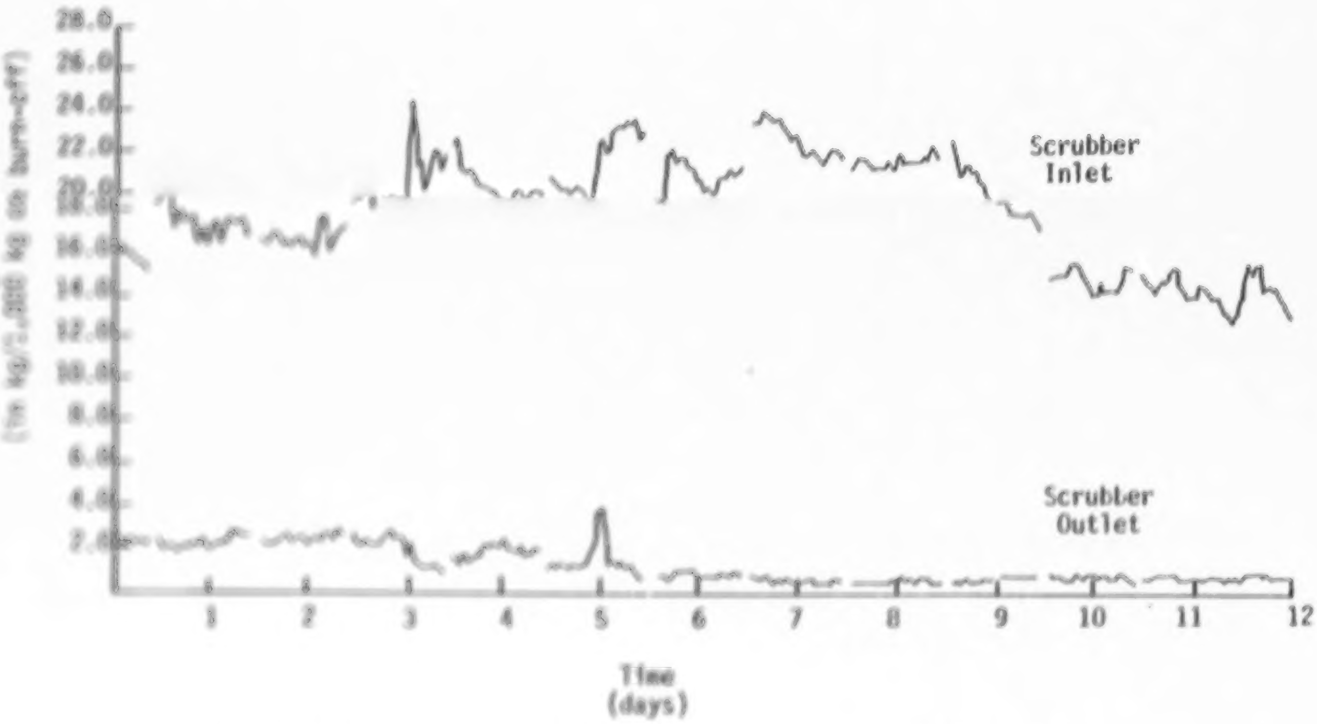

Figure C-1. Results of Flue Gas Scrubber Continuous Monitoring at Refinery A[18]

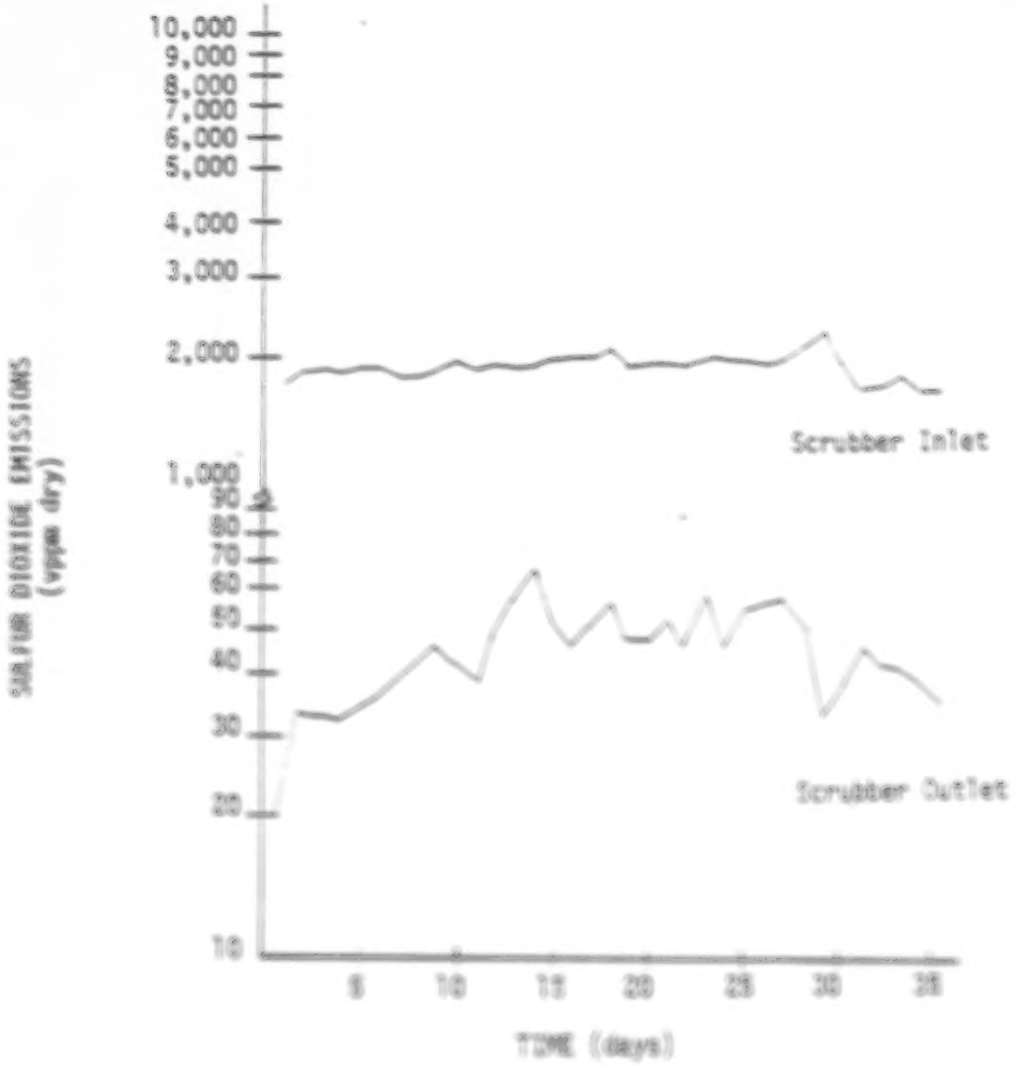

Figure C-2. Results of Flue Gas Scrubber Continuous Monitoring for Industrial Boiler ATD

TABLE C-3. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a]
PLANT A, GUARANTEE TEST

		Scrubber Inlet				Scrubber Outlet			
	Run Number	1	2	3	Average	4	5	6	Average
General Data	Date	4/13/80	4/13/80	4/13/80		4/13/80	4/13/80	4/13/80	
	Time	[illegible]	1240	1600		[illegible]	1240	1335	
	FCC Fresh Feed Charge Rate, m³/sd				11,500				11,500
	FCC Fresh Feed Sulfur Content, wt. %				0.2-0.3				0.2-0.3
	Coke Burn-off Rate, kg/hr				[illegible]				[illegible]
	Isokinetic Ratio, %	102.3	104.0	102.1	102.7	97.0	99.4	98.1	98.3
Gas Data	Scrubber Design Flue Gas Flow Rate, Nm³/min				[illegible]				[illegible]
	Flue Gas Flow Rate, Nm³/min	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Average Stack Gas Velocity, m/s	28.1	27.1	28.6	27.3	15.8	16.2	16.2	16.0
	Stack Temperature, °C	170	172	174	172	56	56	57	56.3
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off g/Nm³ kg/hr	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Collection Efficiency, %					98	98	[illegible]	98
	Test Method	Method 5	Method 5	Method 5		Method 5	Method 5	Method 5	
Sulfur Dioxide Emissions	Concentration, ppm vol	[illegible]	170	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Emission Rate, kg/1,000 kg coke burn-off kg/hr	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Collection Efficiency, %					97	97	[illegible]	[illegible]
	Test Method	Method 6	Method 6	Method 6		Method 6	Method 6	Method 6	
Sulfur Trioxide Emissions	Concentration, ppm vol	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Emission Rate, kg/1,000 kg coke burn-off kg/hr	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Collection Efficiency, %					[illegible]	[illegible]	[illegible]	[illegible]
	Test Method	Method 8	Method 8	Method 8		Method 8	Method 8	Method 8	
Sulfuric Acid Mist Emissions	Concentration, ppm vol	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Emission Rate, kg/1,000 kg coke burn-off kg/hr	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Collection Efficiency, %					[illegible]	[illegible]	[illegible]	[illegible]
	Test Method	Method 8	Method 8	Method 8		Method 8	Method 8	Method 8	
Sulfur Oxides Emissions (as SO_2)	Concentration, ppm vol	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Concentration, ppm dry, O_2-free	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Emission Rate, kg/1,000 kg coke burn-off kg/hr	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Collection Efficiency, %					[illegible]	[illegible]	[illegible]	[illegible]

[a] Data from Reference 1.

TABLE C-4. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT A COMPLIANCE TEST

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	9/3/80	9/3/80	9/4/80	
	Time	1240	1554	1105	
	FCC Fresh Feed Charge Rate, m^3/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr	18,100	17,200	17,200	17,500
	Isokinetic Ratio, %	98.29	101.37	102.62	100.7
Gas Data	Scrubber Inlet Flow Rate, Nm^3/min	4,280	4,220	4,250	4,150
	Regenerator Inlet Flow Rate, Nm^3/min	3,530	3,550	3,630	3,570
	Stack Gas Temperature, °C	63.8	63.8	63.5	63.7
	Average Stack Gas Velocity, m/s	21.8	19.9	19.9	20.5
	Moisture Content, % vol.	18.47	18.36	18.17	18.3
	Molecular Weight of Stack Gas, kg/kg-mole, dry	30.47	30.47	30.4	30.45
	O_2 Concentration, %	4.2	4.2	4.3	4.1
	CO_2 Concentration, %	14.4	14.4	14.3	14.3
	CO Concentration, %	0	0	0	0
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off kg/hr g/Nm^3	3.6 7.8 0.33	3.3 6.3 0.32	3.6 7.2 0.33	3.6 6.5 0.32
	Scrubber Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 5	Method 5	

[a] Data from Reference 4.

TABLE C-5. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a]
PLANT B, TEST 1

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	12/18/77	12/18/77	12/19/77	
	Time	N/A	N/A	N/A	
	FCC Fresh Feed Charge Rate m^3/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr	N/A	N/A	N/A	N/A
	Isokinetic Ratio, %	N/A	N/A	N/A	N/A
Gas Data	Stack Gas Temperature, °C	66	63	63	64
	Average Stack Gas Velocity, m/s	12.9	12.7	13.7	13.1
	Flue Gas Flow Rate, Nm^3/min	9,440	9,530	10,300	9,760
	Moisture Content, %	24.1	23.4	23.1	23.5
	Molecular wt. of Stack Gas, kg/kg-mole	30.7	30.6	30.7	30.7
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off	N/A	N/A	N/A	N/A
	kg/hr	45.1	59.0	54.0	52.7
	g/Nm^3	0.08	0.10	0.09	0.09
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 5	Method 5	--
Sulfur Dioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off	N/A	N/A	N/A	N/A
	kg/hr	101.6	95.7	122.0	106.4
	Concentration, vppm wet	54.4	50.9	60.3	55.2[b]
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 6	Method 6	Method 6	

[a] Data from Reference 7.

[b] The average SO_2 emission concentration reported on a dry basis is 72.7 vppmd. The O_2 content of the flue gas was not reported. As such the SO_2 emission rate could not be reported on a dry, O_2-free basis.

TABLE C-6. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a]
PLANT B, TEST 2

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	5/10/78	5/11/78	5/11/78	
	Time	0230	1045	0400	
	FCC Fresh Feed Charge Rate, m³/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr				36,000[b]
	Isokinetic Ratio, %	95	97	99.9	97.3
Gas Data	Stack Gas Temperature °C	65.6	65.6	65.6	65.6
	Average Stack Gas Velocity, m/s	9.8	12.1	11.6	33.5
	Flue Gas Flow Rate, Nm³/min	7,170	8,970	8,400	8,180
	Moisture Content, %	25	24.9	25	25
	Molecular Weight of Stack Gas kg/kg-mole	29.9	30.6	30.5	30.3
	CO_2 Concentration, % dry	9.6	15.9	15	13.5
	CO Concentration, % dry	0	0.4	0.5	0.3
	O_2 Concentration, % dry	3.8	2.5	3.4	4.9
	N_2 Concentration, % dry	81.6	81.2	81.1	81.3
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off				2.4[b]
	kg/hr	96.2	82.5	76.7	85.1
	g/Nm³	0.22	0.15	0.15	0.17
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 5	Method 5	
Sulfur Dioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off				1.5[b]
	kg/hr	2.2	90.7	64.0	52.3
	Concentration, vppm wet	1.45	43.3	35.7	26.8[c]
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 6	Method 6	Method 6	

[a] Data from Reference 3.

[b] Coke burn-off rate calculated from scrubber outlet test data. Calculation assumes no nitrogen in coke, ambient air contains 78.8 percent nitrogen, 20.0 percent oxygen, and 1.2 percent water, and the flue gas flow rate at the scrubber outlet equals the regenerator flue gas flow rate on a dry basis.

[c] The average SO_2 emission concentration reported on a dry, O_2-free basis is 41.3 vppmd.

TABLE C-7. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT B, TEST 3

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	12/28/78	12/28/78	12/29/78	
	Time	0210	0412	0926	
	FCC Fresh Feed Charge Rate, m^3/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr				45,400[b]
	Isokinetic Ratio, %	103	103	109	105
Gas Data	Stack Gas Temperature, °C	69	73	72	71
	Average Stack Gas Velocity, m/s	13.2	15.0	14.0	14.1
	Flue Gas Flow Rate, Nm^3/min	9,060	9,390	8,640	9,030
	Moisture Content, %	29.5	34	34	30.2
	Molecular Weight of Stack Gas, kg/kg-mole	30.7	30.5	30.5	30.6
	CO_2 Concentration, % dry	16	15.1	15.4	15.5
	CO Concentration, % dry	0	0	0	0
	O_2 Concentration, % dry	2.5	2.0	1.9	2.1
	N_2 Concentration, % dry	81.5	82.9	82.7	82.4
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off				1.5[b]
	kg/hr	72.4	79.4	57.2	69.6
	g/Nm^3	0.13	0.14	0.11	0.13
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 5	Method 5	
Sulfur Dioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off				3.7[b]
	kg/hr	116.6	194.6	188.2	166.5
	Concentration, vppm wet	56.7	85.7	89.9	77.4[c]
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 6	Method 6	Method 6	

[a] Data from Reference 9.

[b] Coke burn-off rate calculated from scrubber outlet test data. Calculation assumes no nitrogen in coke, ambient air contains 78.8 percent nitrogen, 20.0 percent oxygen, and 1.2 percent water, and the flue gas flow rate at the scrubber outlet equals the regenerator flue gas flow rate on a dry basis.

[c] The average SO_2 emission concentration reported on a dry, O_2-free basis is 128 vppmd.

TABLE C-8. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a]
PLANT B, TEST 4

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	5/31/79	5/31/79	6/1/79	
	Time	0949	1506	0912	
	FCC Fresh Feed Charge Rate, m^3/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	
	Coke Burn-off Rate, kg/hr				43,700[b]
	Isokinetic Ratio, %	100	103	103	102
Gas Data	Stack Gas Temperature, °C	70	72	71	71
	Average Stack Gas Velocity, m/s	11.6	11.6	11.4	11.5
	Flue Gas Flow Rate, Nm^3/min	8,210	8,210	8,120	8,180
	Moisture Content, %	26	25.9	25.7	25.9
	Molecular Weight of Stack Gas, kg/kg-mole	30.57	30.57	30.57	30.57
	CO_2 Concentration, % dry	16	16	16	16
	CO Concentration, % dry	0	0	0	0
	O_2 Concentration, % dry	0.3	0.3	0.3	0.3
	N_2 Concentration, % dry	83.7	83.7	83.7	83.7
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off kg/hr g/Nm^3	 68.0 0.138	 64.9 0.132	 75.7 0.156	 1.6[b] 69.5 0.142
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 5	Method 5	
Sulfur Dioxide Emissions	Emission Rate kg/1,000 kg coke burn-off kg/hr	 190.51	 105.23	 191.87	 3.7[b] 162.54
	Concentration, vppm wet	109.5	59.4	107.2	92.0[c]
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 6	Method 6	

[a] Data from Reference 10.

[b] Coke burn-off rate calculated from scrubber outlet test data. Calculation assumes no nitrogen in coke, ambient air contains 78.3 percent nitrogen, 20.0 percent oxygen, and 1.2 percent water, and the flue gas flow rate at the scrubber outlet equals the regenerator flue gas flow rate on a dry basis.

[c] The average SO_2 emission concentration reported on a dry, O_2-free basis is 125.6 vppmd.

TABLE C-9. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT B, TEST 5

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	6/3/80	6/4/80	6/4/80	
	Time	1638	1136	1432	
	FCC Fresh Feed Charge Rate, m^3/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr				26,340[b]
	Isokinetic Ratio, %	102.24	132.45	94.26	109.65
Gas Data	Stack Gas Temperature, °C	70	56	69	68
	Average Stack Gas Velocity, m/s	7.9	7.9	7.9	7.9
	Flue Gas Flow Rate, Nm^3/min	5,870	5,880	6,250	6,000
	Moisture Content, %	21.97	23.56	17.93	21.1
	Molecular Weight of Stack Gas, kg/kg-mole	30.47	30.42	30.39	30.4
	CO_2 Concentration, % dry	14	14	13.8	13.9
	CO Concentration, % dry	0	0	0	0
	O_2 Concentration, % dry	5.8	4.6	4.6	5.0
	N_2 Concentration, % dry	80.2	81.4	81.6	81.1
Particulate Emissions (Filterable)	Emission Rate, kg/1,000 kg coke burn-off				1.09[b]
	kg/hr	29.9	25.6	30.3	28.6
	g/Nm^3	0.085	0.072	0.081	0.08
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 5	Method 5	
Sulfur Dioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off				0.2[b]
	Emission Rate, kg/hr	6.8	3.8	8.1	6.2
	Concentration, vppm wet	5.7	3.1	6.7	5.2[c]
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 6	Method 6	Method 6	

[a] Data from Reference 11.

[b] Coke burn-off rate calculated from scrubber outlet test data. Calculation assumes no nitrogen in coke, ambient air contains 78.8 percent nitrogen, 20.0 percent oxygen, and 1.2 percent water, and the flue gas flow rate at the scrubber outlet equals the regenerator flue gas flow rate on a dry basis.

[c] The average SO_2 emission concentration reported on a dry, O_2-free basis is 8.5 vppmd.

TABLE C-10. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a]
PLANT C, UNIT I

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	9/4/75	9/5/75	9/5/75	
	Time	1550	0956	1340	
	FCC Fresh Feed Charge Rate, m^3/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr				35,700[b]
	Isokinetic Ratio, %	93.5	96.5	99.3	96.4
Gas Data	Stack Gas Temperature, °C	69	70	69	69
	Average Stack Gas Velocity, m/s	10.4	10.6	10.2	10.4
	Flue Gas Flow Rate, Nm^3/min	6,040	6,220	5,930	6,060
	Moisture Content, %	28.6	27.6	29.0	28.4
	Molecular Weight of Stack Gas, kg/kg-mole	25.8	26.8	26.6	25.7
	CO_2 Concentration, % dry	13.0	11.6	11.6	12.1
	CO Concentration, % dry	4.6	5.6	5.6	5.3
	O_2 Concentration, % dry	0	0	0	0
	N_2 Concentration, % dry	82.4	82.8	82.8	82.7
Particulate Emissions	Emission Rate kg/1,000 kg coke burn-off kg/hr g/Nm^3	 33.3 0.09	 25.8 0.07	 25.1 0.07	 0.8[b] 28.1 0.09
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	N/A	N/A	N/A	N/A
Sulfur Dioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off kg/hr	 233.8[c]	 47.8[c]	 53.4[c]	 3.1[b] 111.8[c]
	Concentration, vppm wet	188.2	37.6	43.7	89.8
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	N/A	N/A	N/A	N/A

TABLE C-10. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT C, UNIT I (Concluded)

		Scrubber Outlet			
Run Number		1	2	3	Average
Sulfur Trioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off kg/hr	 3.2[c]	 2.8[c]	 2.7[c]	 0.08[b] 2.9[c]
	Concentration, vppm wet	2.1	1.3	1.8	1.9
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	N/A	N/A	N/A	N/A
Sulfur Oxides Emissions (as SO_2)[c]	Concentration, vppm wet	190	39.4	45.5	91.6
	Concentration, vppm dry, O_2-free	341	74.1	87.3	167
	Emission Rate, kg/1,000 kg coke burn-off kg/hr	 237	 50.0	 55.4	 3.2[b] 114
	Collection Efficiency, %	N/A	N/A	N/A	N/A

[a] Data from Reference 13.

[b] Coke burn-off rate calculated from scrubber outlet test data. Calculation assumes no nitrogen in coke, ambient air contains 78.8 percent nitrogen, 20.0 percent oxygen, and 1.2 percent water, and the flue gas flow rate at the scrubber outlet equals the regenerator flue gas flow rate on a dry basis.

[c] Calculated from test results.

TABLE C-11. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a]
PLANT C, UNIT II

		Scrubber Outlet			
Run Number[b]		2	3	4	Average
General Data	Date	4/21/76	4/22/76	4/22/76	
	Time	1543	1122	1535	
	FCC Fresh Feed Charge Rate	N/A	N/A	N/A	10,600[c]
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr				21,400[e]
	Isokinetic Ratio, %	99.5	102.0	101.2	100.9
Gas Data	Stack Gas Temperature, °C	70	69	72	70
	Average Stack Gas Velocity, m/s	13.2	13.7	13.5	13.5
	Flue Gas Flow Rate, Nm^3/min	3,690	3,810	3,740	3,750
	Moisture Content, %	24.0	24.3	24.4	24.4
	Molecular Weight of Stack Gas, kg/kg-mole	27.6	27.4	27.5	27.5
	CO_2 Concentration, % dry	15.8	15.4	15.4	15.6
	CO Concentration, % dry	1.9	1.6	1.6	1.7
	O_2 Concentration, % dry	0	0	0	0
	N_2 Concentration, % dry	82.3	83.0	83.0	83.1
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off				1.2[e]
	kg/hr	23.0	28.2	26.0	25.7
	g/Nm^3	0.10	0.12	0.12	0.12
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	N/A	N/A	N/A	
Sulfur Dioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off				0.3[e]
	kg/hr	5.0[d]	6.8[d]	7.1[d]	6.3[d]
	Concentration, vppm wet	6.9	8.9	9.6	8.5
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	N/A	N/A	N/A	N/A

TABLE C-11. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT C, UNIT II (Concluded)

		Scrubber Outlet			
Run Number		2	3	4	Average
Sulfur Trioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off				0.08[e]
	kg/hr	1.5[d]	1.8[d]	1.8[d]	1.8[d]
	Concentration, vppm wet	2.1	1.9	2.0	2.0
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	N/A	N/A	N/A	
Sulfur Oxides Emissions (as SO_2)[d]	Concentration, vppm wet	8.9	10.8	11.5	10.4
	Concentration, vppm dry, O_2-free	12.9	15.6	16.6	15.0
	Emission Rate, kg/1,000 kg coke burn-off				0.7[e]
	kg/hr	6.5	8.2	8.6	7.7
	Collection Efficiency, %	N/A	N/A	N/A	N/A

[a] Data from Reference 14.

[b] Run one was voided due to unacceptable isokinetic percentage.

[c] Capacity obtained from Reference 15.

[d] Calculated from test data.

[e] Coke burn-off rate calculated from scrubber outlet test data. Calculation assumes no nitrogen in coke, ambient air contains 78.8 percent nitrogen, 20.0 percent oxygen, and 1.2 percent water, and the flue gas flow rate at the scrubber outlet equals the regenerator flue gas flow rate on a dry basis.

TABLE C-12. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT D, COMPLIANCE TEST

		Scrubber Outlet			
Run Number		1	2	3	Average
General Data	Date	5/19/81	5/19/81	5/19/81	
	Time	1425	1754	1952	
	FCC Fresh Feed Charge Rate, m³/sd	N/A	N/A	N/A	N/A
	FCC Fresh Feed Sulfur Content, wt. %	N/A	N/A	N/A	N/A
	Coke Burn-off Rate, kg/hr	N/A	N/A	N/A	8,763
	Isokinetic Ratio, %	95.9	98.9	99.0	97.9
Gas Data	Scrubber Inlet Flow Rate, Nm³/min	1,703	1,716	1,814	1,744
	Regenerator Inlet Flow Rate, Nm³/min	N/A	N/A	N/A	N/A
	Stack Gas Temperature, °C	58	57	57	57
	Average Stack Gas Velocity, m/s	15.0	15.1	15.9	15.3
	Moisture Content, % Vol.	16.8	16.5	16.6	16.6
	Molecular Weight of Stack Gas, kg/kg-mole, dry	30.7	30.7	30.8	30.7
	O_2 Concentration, % dry	2.3	2.5	2.3	2.4
	CO_2 Concentration, % dry	16.1	16.2	16.6	16.3
	CO Concentration, % dry	ND[b]	ND[b]	ND[b]	ND[b]
Particulate Emissions	Emission Rate kg/1,000 kg coke burn-off kg/hr g/Nm³	 N/A 3.9 0.028	 N/A 4.6 0.033	 N/A 4.3 0.030	 0.5 4.3 0.030
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 5	Method 5	Method 5	Method 5
Sulfur Dioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off kg/hr	 N/A 0.79	 N/A 1.0	 N/A 1.3	 0.1 1.0
	Concentration, vppm dry	2.9	3.7	4.5	3.7
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 6	Method 6	Method 5	Method 6

TABLE C-12. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT D, COMPLIANCE TEST (Concluded)

		Scrubber Outlet			
Run Number		1	2	3	Average
Sulfur Trioxide Emissions	Emission Rate, kg/1,000 kg coke burn-off	N/A	N/A	N/A	0.02
	kg/hr	0.14	0.21	0.18	0.18
	Concentration, vppm dry	0.4	0.6	0.5	0.5
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	N/A	N/A	N/A	N/A
Sulfur Oxides Emissions (as SO_2)[d]	Concentration, vppm dry	3.3	4.3	5.0	4.2
	Concentration, vppm dry, O_2-free	3.7	4.9	5.6	4.7
	Emission Rate, kg/1,000 kg coke burn-off				0.1
	kg/hr	0.9	1.2	1.5	1.2
	Collection Efficiency, %	N/A	N/A	N/A	N/A
Nitrogen Oxides Emissions	Emission Rate, kg/1,000 kg coke burn-off	N/A	N/A	N/A	3.8
	kg/hr	35.8	33.3	29.9	33.0
	Concentration, vppm wet	186.4	171.7	145.9	168.0
	Collection Efficiency, %	N/A	N/A	N/A	N/A
	Test Method	Method 7	Method 7	Method 7	Method 7

[a] Data from Reference 16.

[b] Not detected.

TABLE C-13. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a]
PLANT D, GUARANTEE TEST

		Scrubber Inlet				Scrubber Outlet			
	Run Number	1	2	3	Average	1	2	3	Average
General Data	Date	5/6/81	5/6/81	5/6/81		5/6/81	5/6/81	5/6/81	
	Time	0905	1140	1410		0847	1130	1417	
	FCC Fresh Feed Change rate, m³/sd				N/A				N/A
	FCC Fresh Feed Sulfur Content, wt. %				0.26				0.26
	Coke Burn-off Rate, kg/hr				N/A	9,116	9,025	8,844	8,995
	Isokinetic Ratio, %				N/A	102	104	103	103
Gas Data	Flue Gas Flow Rate, Nm³/min	1,846	1,900	1,934	1,893	1,841	1,838	1,863	1,847
	Average Stack Gas Velocity, m/s	43	44	44	44	41	41	42	41
	Stack Temperature, °C	355	331	336	341	133	135	139	136
Particulate Emissions	Emission Rate, kg/1,000 kg coke burn-off g/Nm³ kg/hr				N/A N/A N/A	0.2 0.02 2.1	0.3 0.02 2.2	0.3 0.02 2.5	0.3 0.02 2.3
	Collection Efficiency, %								N/A
	Test Method	Method 5	Method 5	Method 5		Method 5	Method 5	Method 5	
Sulfur Dioxide Emissions	Concentration, vppm dry	144	159	148	150	5.9	6.2	10.5	7.5[b]
	Emission Rate, kg/1,000 kg coke burn-off kg/hr	43	49	46	5.1 46	1.8	1.9	3.2	0.3 2.3
	Collection Efficiency, %					96	96	93	95
	Test Method	Method 6	Method 6	Method 6	Method 6	Method 6	Method 6	Method 6	Method 6

[a] Data from Reference 17.

[b] The average SO_2 emission concentration at the scrubber outlet, reported on a dry, O_2-free basis is 8.8 vppmd.

Table C-14. FLUE GAS SCRUBBER EMISSIONS TEST DATA[a] PLANT A, EPA-CONDUCTED SOURCE TEST

		Minimum	Maximum	Average	Number of Data Points
General Data	Dates 5/5-30/81				
	Fresh Feed Rate, m³/sd	N/A	N/A	N/A	
	Fresh Feed Sulfur Content, wt.%	0.32	0.60	0.46	26 daily
	Coke Burn-off Rate, kg/hr	12,800	17,200	15,300	266 hourly
Particulate Emissions	Dates 5/27-30/81				
	kg/1,000 kg coke burn-off[b]				
	scrubber inlet	2.9	8.8	6.4	8
	scrubber outlet	0.22	1.5	0.9	8
	g/Nm³				
	scrubber inlet	0.15	0.72	0.41	8
	scrubber outlet	0.007	0.10	0.06	8
	kg/hr				
	scrubber inlet	38.6	118.7	77.2	8
	scrubber outlet	7.6	20.1	12.4	8
	Emissions Reduction, wt.%	80.3	89.1	83.3	8
Sulfur Dioxide Emissions (by Continuous Monitoring)	Dates 5/17-28/81				
	kg/1,000 kg coke burn-off				
	scrubber inlet	12.6	24.4	18.6	266 hourly
	scrubber outlet	0.4	4.0	1.3	266 hourly
	Removal Efficiency, wt.%	82.2	98.2	93.0	266 hourly
Sulfur Oxides Emissions (by Stack Tests)	Dates 5/27-30/81				
	Sulfur Dioxide (vppm)				
	scrubber inlet	339	397	370	9
	scrubber outlet	15.8	25.5	19.9	9
	Removal Efficiency, wt.%	92.9	95.7	94.6	9
	Sulfur Trioxide (vppm)				
	scrubber inlet	2.6	8.8	4.8	9
	scrubber outlet	0.3	1.4	0.8	7
	Removal Efficiency, wt.%	80.4	94.4	84.4	7
	Sulfates (vppm)				
	scrubber inlet	7.5	23.2	15.0	9
	scrubber outlet	2.5	10.8	6.3	8
	Removal Efficiency, wt.%	38.0	80.8	56.0	8
Hydrocarbon Emissions	Dates 5/8-9/81				
	Scrubber Outlet Concentration (vppm)				
	C_1 Hydrocarbon	17.9	21.5	19.7	6
	C_2 Hydrocarbons	0.0	2.4	1.7	6
	C_3 Hydrocarbons		NOT DETECTED		
	C_4 Hydrocarbons	0.0	2.5	1.3	6
	C_5,C_6 Hydrocarbons		NOT DETECTED		
	TOTAL C_{1-6} Hydrocarbons	18.7	26.6	22.7	6
Nitrogen Oxides Emissions	Dates 5/7-8/81				
	Scrubber Outlet Concentration (vppm dry)	85.4	99.4	93.1	3

[a] Data from Reference 19.

[b] 5/27-29/81 only.

TABLE C-15. SULFUR OXIDES REDUCTION CATALYST TEST DATA[a]
PLANT E, TEST 1

		Pretest	Steady State
General Data	Dates	8/18/80	11/13/80
	Fresh Feed Rate, m^3/sd	3,300	3,000
	Fresh Feed Sulfur Content, wt.%	0.99	1.07
	Coke Burn-off Rate, kg/hr	7,480	6,350
Gas Data	Regenerator Flue Gas Temperature, °C	690	660
	Flue Gas Flow Rate, Sm^3/min	1,380	1,130
	O_2 Concentration, Vol.%	2.3	2.0
Particulate Emissions	Emission Rate[b]		
	kg/1,000 kg coke burn-off	2.2	2.7
	kg/hr	16.5	16.9
	g/Nm^3	0.19	0.23
Sulfur Oxides Emissions[c]	Emission Rate,		
	vppm	413	86
	kg/hr (as SO_2)	91.3	15.6
	kg/1,000 kg coke burn-off (as SO_2)	12.2	2.5
Sulfur Dioxide Emissions[d]	Emission Rate		
	vppm	350	60
	kg/hr	77.5	10.9
	kg/1,000 kg coke burn-off	10.4	1.7
Nitrogen Oxides Emissions[c]	Emission Rate		
	vppm	163	NA[e]
	kg/hr (as NO_2)	25.8	NA
	kg/1,000 kg coke burn-off (as NO_2)	3.4	NA
Nitric Oxide[d] Emissions	Emission Rate		
	vppm	110	700
	kg/hr	11.4	59.5
	kg/1,000 kg coke burn-off	1.5	9.4

[a] Reference 21.

[b] Sampling dates for pretest and steady-state period are 8/8/80 and 11/4/80, respectively.

[c] Wet chemical analysis.

[d] Instrumental analysis.

[e] Not available.

TABLE C-16. SULFUR OXIDES REDUCTION CATALYST TEST DATA[a] PLANT F, TEST 1

		Pretest	Steady State	
	Dates	12/2/80	1/24/81	3/18/81
General Data	Fresh Feed Rate, m³/sd	3,400	3,020	3,020
	Fresh Feed Sulfur Content, wt.%	1.0	1.06	1.37
	Coke Burn-off Rate, kg/hr	6,210	5,940	5,900
Gas Data	Regenerator Flue Gas Temperature, °C	677	682	670
	Flue Gas Flow Rate, Sm³/min	1,270	1,230	1,180
	O_2 Concentration, Vol.%	2.5	2.55	2.0
Sulfur Oxides Emissions[b]	Emission Rate,			
	vppm	303	103	155
	kg/hr (as SO_2)	61.7	20.2	29.3
	kg/1,000 kg coke burn-off (as SO_2)	9.9	3.4	5.0
Sulfur Dioxide Emissions[c]	Emission Rate			
	vppm	300	85	100
	kg/hr	61.1	16.7	18.9
	kg/1,000 kg coke burn-off	9.8	2.8	3.2
Nitrogen Oxides Emissions	Emission Rate[b]			
	vppm	707	1,071	1,306
	kg/hr (as NO_2)	103	151	177
	kg/1,000 kg coke burn-off (as NO_2)	16.6	25.4	30.0
	Emission Rate[c]			
	vppm	590	1,050	1,200
	kg/hr	86.3	148	163
	kg/1,000 kg coke burn-off	13.9	24.9	27.6

[a] Reference 21.

[b] Wet chemical analysis.

[c] Instrumental analysis.

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APPENDIX D
EMISSION MEASUREMENT AND CONTINUOUS MONITORING

D.1 EMISSION MEASUREMENT METHODS

D.1.1 Emission Testing Program

A single emission test program for NSPS development was performed by EPA/EMB. The objective of this test program was to obtain approximately 14 days of continuous emissions data from a fluid catalytic cracking unit (FCCU) fed with 0.2 to 0.3 percent sulfur feed and equipped with a high energy venturi-wet scrubber system (HEV-WSS) for SO_2 control. The host site was Marathon Oil Company's refinery, Garyville, Louisiana. Continuous emissions monitoring was performed for 12 days on both the inlet and outlet of the HEV-WSS in order to determine SO_2 removal efficiency. Relative accuracy of the continuous emissions monitoring system was determined using the modified Method 8 reference method. Relative accuracy was within the specifications of proposed Performance Specifications 2 and 3, Federal Register, Volume 44, No. 197, October 10, 1979, and Federal Register, Volume 46, No. 16, January 26, 1981. Data on SO_2/SO_3 and particulate sulfate, nitrogen oxides, hydrocarbon and particulate emissions were also collected during this test program. Additionally, samples of the product feed to the fluid catalytic cracking unit and samples of the scrubber purge water were collected.

D.1.1.1 Scrubber Inlet. Volumetric flow and moisture were determined by EPA Reference Methods 1, 2, 3, and 4 with the following minor modifications:

a) Because the HEV-WSS inlet sampling port was under high temperature and pressure (360°F and 40 inches of water), special port adapters and sampling probes had to be fabricated for the test program (Figure D-1). Due to the close proximity of the scrubber disengaging drum to the south port on the scrubber inlet, the manual sampling probe could only be used on the west port. However, from previous test information,[1] sampling from one port was determined to be equivalent for this site.

b) Moisture was determined by measuring the moisture collected in the impinger train during each modified Method 8 SO_2/SO_3 test.

SO_2/SO_3 and particulate sulfate were determined using EPA Reference Method 8 with the following modifications:

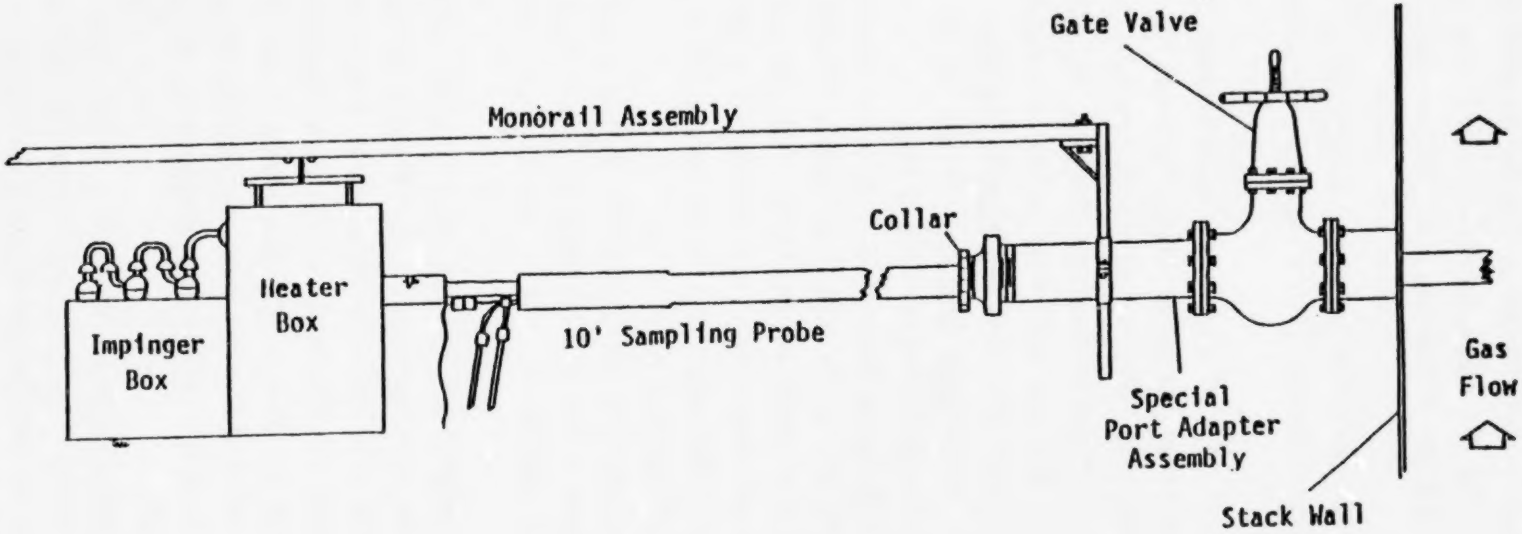

Gate Valve
Monorail Assembly
Collar
Heater Box
Impinger Box
10' Sampling Probe
Gas Flow
Special Port Adapter Assembly
Stack Wall

Figure D-1. Manual sampling port adapter.

a) A heated filter housed in a standard RAC^R train heater box was used. The box temperature was maintained at approximately 350°F and the filter medium used was Reeve Angel 934 H glass fiber.

b) 100 ml of acidified 80 percent isopropanol (IPA) was placed in the first impinger (1.0 N hydrochloric acid added to 20 parts water).

c) Packed glass wool plug was placed between the IPA impinger and first hydrogen peroxide (H_2O_2) impinger to prevent particulate sulfates from carrying over into the H_2O_2 impinger.

In addition, continuous monitors for SO_2, CO_2, CO, O_2 and temperature were installed and operated according to the procedures outlined in Performance Specifications 2 and 3, Federal Register, Volume 44, No. 197, October 10, 1979, and Federal Register, Volume 46, No. 16, January 26, 1981, except for the following modifications:

a) The conditioning period was 105 hours instead of 168 hours. This was due to the time constraints of this test program.

b) Relative accuracy was performed from the 9th through 12th day of the continuous emissions monitoring program. This was necessary because of the relatively short (12 days) continuous emissions monitoring program.

The relative accuracy tests used EPA Method 3 and modified Method 8 as reference methods. The SO_2 analyses were performed in accordance with EPA Method 6, Section 4. The O_2 and CO_2 analyses were by the Orsat method.

In order to determine emissions data in terms of kilograms of SO_x per 1,000 kilograms coke burn-off, a correlation was established between the volumetric flow rate into the regenerator (recorded by the company's flow rate instrument and furnished to EPA) and the volumetric flow rate into and out of the scrubber. This was accomplished by comparing scrubber inlet and outlet volumetric flow rates determined during manual testing to the flow rate into the regenerator recorded by the company during the same period of time.

D.1.1.2 Scrubber Outlet. Volumetric flow and moisture were determined by EPA Reference Methods 1, 2, 3, and 4 with the following minor modification:

a) Moisture was determined in the same manner as described for the scrubber inlet.

SO_2/SO_3 and particulate sulfate were determined in the same manner as described for the scrubber inlet.

Nitrogen oxides emissions were determined by EPA Method 7. Hydrocarbon emissions were determined by EPA Method 3 and analysis performed in the field by GC/FID for C_1 - C_6 carbon fractions.

Continuous monitors for SO_2, CO_2, O_2 and temperature were installed as described for the scrubber inlet.

D.1.1.3 Product Feed to FCCU. During this test program, the refinery's hydrodesulfurization system was off-line, and all feedstock to the FCCU was supplied from storage tanks. Daily analysis for sulfur content of the feedstock to the FCCU was performed by the refinery and the results furnished to EPA. Grab samples of the feedstock were furnished to EPA at each storage tank change.

D.1.1.4 Scrubber Purge Water. Grab samples of the scrubber purge water were taken at each feedstock storage tank change. The samples were analyzed for total dissolved solids, total suspended solids, and chemical oxygen demand.

D.1.2 Modification to EPA Method 8

Previous evaluations by EPA and others indicated that EPA Method 8, as written, may produce erroneous SO_x concentration results due to ammonia (NH_3) concentrations present in FCCU flue gas streams. (In the presence of isopropanol, free ammonia reacts with SO_2 to form a particulate sulfate in the first impinger.) Existing test data that would indicate the NH_3 concentrations in flue gas streams from high temperature regenerators were not available; therefore, it was necessary to modify the EPA Method 8 sampling train to ensure no NH_3 interference in the SO_2/SO_3 sampling performed during this test program.

Control tests during the test program indicated no NH_3 concentrations present at this site because no interference was detected in the SO_2/SO_3 analyses.

D.1.3 Development of Modified Method 8 Train

Two methods for removing NH_3 were considered:

1) Place an impinger upstream of the SO_2/SO_3 train with a concentrated sulfuric acid (H_2SO_4) scrubber (50 percent by wt.). Any NH_3 in the gas sample would form ammonium sulfate in this impinger with the SO_2 and SO_3 passing through unreacted; and

2) Place an impinger upstream of the SO_2/SO_3 train with a weak (1.0 N) hydrochloric acid (HCl) scrubber. Ammonium chloride is formed in this impinger with the SO_2 and SO_3 passing through unreacted. The HCl impinger was chosen because sulfuric acid mist was believed to be present in the flue gas to be tested and also any H_2SO_4 scrubber carryover would add $SO_4^{=}$ to the SO_2 impinger, HCl would not.

D.1.3.1 Laboratory Evaluation of Method 8 Sampling Train With HCl Impinger. A series of 11 sample runs were conducted in the laboratory using a noncertified calibration gas containing 25 vppm of SO_2 in a dry nitrogen base (a tag attached to the gas cylinder indicates that the SO_2 concentration was analyzed to be 25.8 vppm).

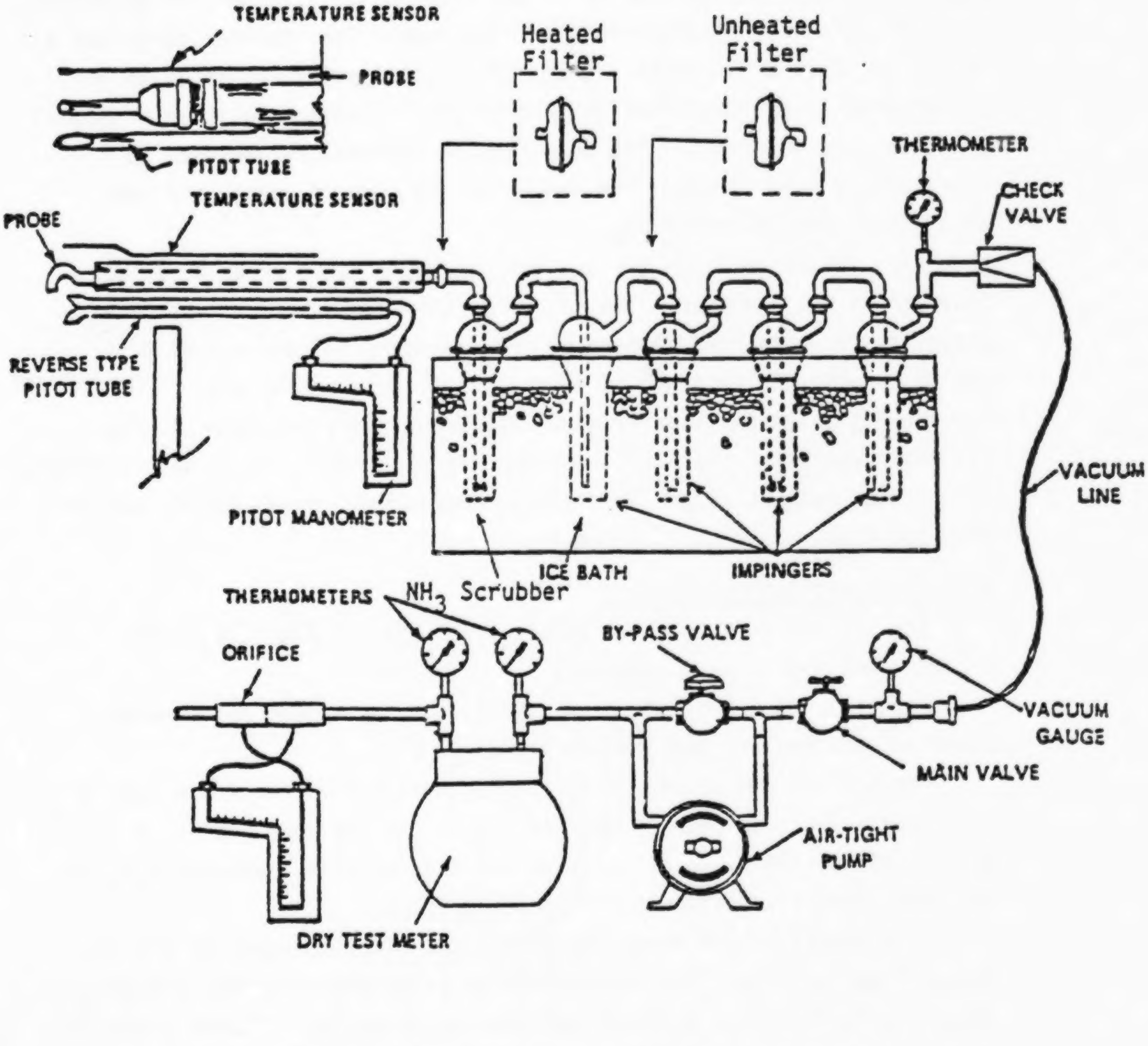
The proposed, modified Method 8 sample train (see Figure D-2) consisted of a heated probe and filter followed by a 1.0 N HCl scrubber (to remove ammonia), 80 percent IPA impinger, a cold filter, and two 3 percent H_2O_2 impingers each containing 100 ml of solution. A final impinger contained silica gel. During the laboratory tests, the probe and filter were kept between 300 to 350°F, and the solution of the first impinger was changed often and injected with a fixed amount of NH_4OH solution to represent approximately 40 vppm NH_3 in the calibration gas. The volume of calibration gas drawn through the sample train varied from 3 to 4.5 dscf and was sufficient for analysis to fall within the accurate range using 0.01 N barium perchlorate titration.

Sampling and Analysis

The laboratory evaluation of the experimental Method 8 sampling train was performed in six phases. These six phases are as described:

Phase 1: Sample runs 1, 3, and 11 were conducted by simultaneous, dropwise injection of 0.03 N NH_4OH into the HCl scrubber (40 vppm). Concentrations of SO_2 in the H_2O_2 were measured as 24.4, 24.1, and 25.0 vppm, respectively. No sulfates were detected in the HCl scrubber and 80 percent IPA impinger.

Phase 2: On sample run 2, the HCl scrubber was left out and ammonia injection was made directly into the 80 percent IPA impinger. Analysis for SO_2 in the H_2O_2 impingers revealed only 5.4 vppm. No sulfate was detected in the IPA impinger, nor was any sulfate detected after treating an aliquot from the IPA impinger with 3 percent H_2O_2.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PROBE
PITOT TUBE
Heated Filter
Unheated Filter
THERMOMETER
CHECK VALVE
PROBE
TEMPERATURE SENSOR
REVERSE TYPE PITOT TUBE
PITOT MANOMETER
VACUUM LINE
ICE BATH
IMPINGERS
NH3 Scrubber
THERMOMETERS
ORIFICE
BY-PASS VALVE
VACUUM GAUGE
MAIN VALVE
AIR-TIGHT PUMP
DRY TEST METER

Figure D-2. Experimental EPA Method 8 Train to Include NH_3 Scrubber

Phase 3: Sample runs 4, 5, 6, and 7 were conducted as control standards (no HCl impinger/no NH_4OH injection). The respective analyses for SO_2 in the H_2O_2 impingers were 23.8, 24.8, 26.1, 23.5 vppm. During sample run 6, the solution in the 80 percent IPA impinger was accidentally left out. No sulfate was found in the IPA impingers.

Phase 4: During sample runs 8, 9, and 10, the HCl scrubber and 80 percent IPA impingers were combined into one impinger. The impinger contained a 100 ml solution of 80 parts IPA and 20 parts of 1.0 N HCl solution and is referred to as "acidified 80 percent IPA." Known quantities of NH_4OH solution were injected in the acidified 80 percent IPA impinger to represent 40 vppm of NH_3. The resulting analyses of these runs were 28.1, 27.7, and 26.7 vppm SO_2.

Phase 5: The calibration gas was analyzed by a TECO Series 40/pulsed fluorescent SO_2 analyzer. The value for this run was 27.95 vppm SO_2.

Phase 6: The acidified 80 percent IPA impingers on sample runs 8, 9, and 10 and the HCl impinger in sample run 11 were spiked with 10 ml of 0.1 N H_2SO_4 solution (exactly 49.0 milligrams H_2SO_4 per sample). By titration analysis, the H_2SO_4 recovery was 49.9, 49.9, 48.6, 49.9 milligram per sample, respectively. The spiking represented approximately 100 to 140 vppm H_2SO_4.

Discussion and Recommendations

The SO_2 recovery involved phases 1 through 5. The H_2SO_4 mist recovery was evaluated in phase 6.

Phases 1 and 3 indicate a relatively good agreement but somewhat lower values than the analyzed 25.8 vppm SO_2.

Phase 2 was evaluated further since the lower value of 5.4 vppm SO_2 indicated a reaction between NH_3 and SO_2 in the impinger train. A portion of the IPA impinger solution was treated with 3 percent H_2O_2 and analyzed, but no significant effect was noticed.

As a result of the foregoing tests, the first impinger of the EPA Method 8 was modified (see Figure D-3) by using the acidified IPA solution described in Phase 4. Analysis was done using Barium - Thorin titration.

D.1.3.2 Field Test Analysis Problems. During the field test program, SO_3 could not be determined in the field due to difficulty in

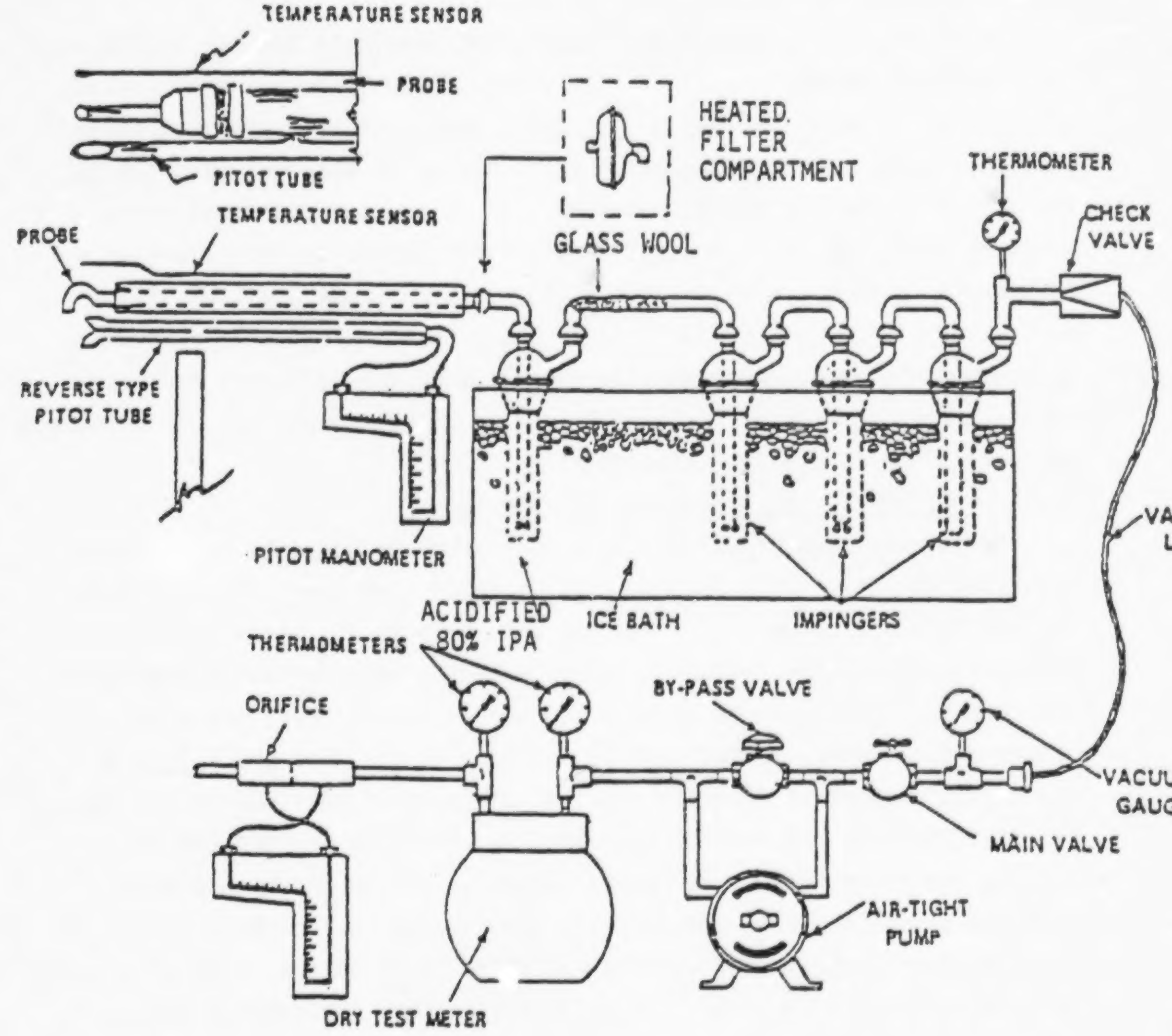
TEMPERATURE SENSOR
PROBE
PITOT TUBE
HEATED FILTER COMPARTMENT
THERMOMETER
CHECK VALVE
PROBE
TEMPERATURE SENSOR
GLASS WOOL
REVERSE TYPE PITOT TUBE
VACUUM LINE
PITOT MANOMETER
ACIDIFIED 80% IPA
ICE BATH
IMPINGERS
THERMOMETERS
ORIFICE
BY-PASS VALVE
VACUUM GAUGE
MAIN VALVE
AIR-TIGHT PUMP
DRY TEST METER

Figure D-3. Modified EPA Method 8 with acidified IPA impinger.

determining end-point in the Thorin titration. This problem did not appear to be due to the HCl in the IPA impinger, but due to some other interference.

The SO_3 and particulate sulfate (SO_4) samples were later analyzed in a laboratory by ion chromatographic analysis.

D.2 MONITORING SYSTEMS AND DEVICES

A variety of SO_2 monitoring systems are available for use at FCC unit catalyst regenerator facilities. Due primarily to the similarities of FCC unit catalyst regenerator exhausts and those of coal-fired steam generator exhausts, no substantive difficulties in adapting existing SO_2 monitoring technology are anticipated. It is assumed that monitoring would be performed as an indication of proper operation and maintenance of control systems. This section will present a brief overview of the cost, composition, and reliability of SO_2 continuous emission monitoring systems (CEMS) required to monitor emissions in two different formats. These formats are (1) parts per million, by volume (vppm) and (2) kilograms SO_2 per 1,000 kilograms coke burnoff.

D.2.1 CEMS Monitor SO_2 Emissions in vppm Format

Performance specifications have been proposed adequate to evaluate the acceptability of SO_2 CEMS in this format.[2] Two types of continuous SO_2 monitors are commercially available to measure SO_2 emissions. Extractive monitoring systems withdraw a small, representative sample of the flue gas; transport the sample to the gas conditioner; and after proper conditioning, measure the SO_2 content of the flue gas. *In-situ* monitoring systems perform the required analysis of the flue gas inside the stack without the need to transport or condition the gas sample. *In-situ* analyzers must be extremely rugged to circumvent maintenance problems associated with the normally harsh stack environment.

The capital cost of a CEMS is estimated to be in the range of \$69,000 to \$90,000 per site (including the initial performance test), depending on the type of system chosen by the company and the complexity of the installation requirements. Equipment costs were obtained from vendors;[3,4] other costs are based on engineering estimates. Annual operating cost per site is estimated to be in the range of \$11,000 per year. Table D-1 provides a more thorough breakdown of estimated costs.

TABLE D-1. SO_2 CONTINUOUS MONITORING COST

Option	Equipment Cost	Installation	Initial Performance Cost	Total Initial Capital Cost	Routine Labor	Materials	Total Annual Operating Cost
Outlet Emission (vppm) Continuous Monitors	\$39,000-60,000[a]	\$20,000	\$10,000	\$59,000 to \$80,000	\$10,000	\$1,000	\$11,000
Automated Reference Method 6B	\$2,000	---	---	\$2,000	\$50/sample[b]	---	\$18,000[c]

[a] Includes estimate of \$20,000 for data acquisition system. Range provided because of varied cost of different type SO_2 monitoring systems.

[b] Includes both labor and materials.

[c] Annual cost is highly dependent on the sampling frequency. Cost presented is for daily one-point sampling. Multipoint sampling would add proportionately.

FCCU catalyst regenerator exhausts are similar to those of coal-fired steam generators; therefore, the continuous SO_2 monitoring technology proven acceptable for steam generators should be applicable to FCCU catalyst regenerators. SO_2 monitors have been installed on some FCCU catalyst regenerators. The Emission Measurement Branch (EMB) has not gathered information on the operational history of those CEMS; however, properly designed systems should be capable of meeting the performance specifications proposed by EPA. Reliability of the CEMS system to date at steam generators and industrial boilers appears to vary widely depending on the type of flue gas desulfurization system employed. SO_2 monitors installed on sodium-based scrubbers appear to have a reliability of greater than 90 percent while those installed on lime/limestone scrubbers had a reliability of 37 to 85 percent based on short term (30- to 90-day) EPA tests.[5] The primary problems at the latter sites appeared to be in particulate plugging of the sampling probe in the stack. Redesign of this should improve the reliability of the CEMS. Information submitted by one company indicates 88 percent reliability of one system at a lime/limestone scrubber system over a period of 1 year.[6] Reliability at FCCU catalyst regenerators is expected to be similarly affected by the type of control system employed.

EPA has developed Method 6B that makes use of the combined SO_2 and CO_2 measurement capabilities of Method 6A in a long-term sampling method. Method 6B can be operated intermittantly (2 to 4 minutes per hour at 1 liter per minute for 24 hours) using a timing switch to obtain representative daily samples. Alternatively, a low-flow (50 ml per minute) pump may be used to sample continuously over 24 hours or intermittantly over longer periods (3 to 7 days) to obtain a longer term, average value. Method 6B can be applied as an emission monitoring method by operating the equipment automatically at the appropriate emission points and analyzing the collected samples on-site.

Manpower requirements are less for Method 6B than for Method 6 as only one test train is operated at a test point instead of the three test runs that constitute a Method 6 run. One person can prepare fresh chemicals, remove the used collection section, replace with the fresh train, and analyze the collected samples in less than 1/2 day. The training necessary is a knowledge of simple laboratory techniques. Costs of chemicals and manpower should be less than $50 per test run. Annual costs would range from about $3,000 for one point, weekly samples, to $58,000 for multipoint, daily measurements.

D.2.2 CEMS to Monitor SO_2 Emissions in Kilograms SO_2 Per Kilogram Coke Burn-Off Format.

Monitoring SO_2 emissions in kilograms SO_2 per 1,000 kilograms coke burn-off requires that the following parameters be used in the calculation:

- Control device exhaust gas SO_2 (vppm)
- Control device exhaust gas CO_2 (vppm)
- Control device exhaust gas O_2 (vppm)
- Control device exhaust gas temperature
- Control device exhaust gas velocity pressure
- Control device exhaust gas moisture (percent)
- Control device inlet gas CO_2 (vppm)
- Control device inlet gas velocity pressure
- Control device inlet gas moisture (percent)
- Control device inlet gas CO (vppm)
- Control device inlet gas temperature
- Air rate to FCCU catalyst regenerator (@ std conditions)

Based on EMB experience to date with CEMS, primarily at steam generators where only two parameters are measured (SO_2 and diluent O_2 or CO_2) the reliability of a system with 12 to 14 parameters would be extremely low. Sufficient information on the reliability of the individual components has not been obtained to allow an accurate prediction of this reliability, however.

The second major problem with monitoring in this format is that the relative accuracy of the CEMS is unknown. Performance specifications would need to be developed for such a system. As with reliability, the relative accuracy of the CEMS would be a function of the combined errors of the precision and accuracy of the various system components (in relation to the reference methods). Development of a new performance specification would take a minimum of 3 years to propose. Notice of intent to require such monitoring could be incorporated into the regulation with applicability automatically being delayed until proposal and promulgation.

The capital cost to monitor SO_2 in the kg SO_2 per 1,000 kg coke burn-off format is estimated to be in the range of $80,000 to $100,000. The additional costs beyond those shown in Table D-1 are for two velocity pressure monitors and a control device exhaust gas CO_2 monitor. The other parameters itemized earlier are assumed to be installed for process monitoring purposes. Annual operating costs would increase slightly due primarily to additional supplies required.

D.3 PERFORMANCE TEST METHODS

D.3.1 Stack Emissions

Reference Method 8, "Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources," in conjunction with Reference Methods 1, 2, 3, and 4, as required, are recommended for determining sulfur oxides (SO_x) emissions reported as sulfur dioxide. If the recommended standard is a concentration format (vppm), then Method 8 would be required at the control device exhaust.

One modification in the calculation procedures specified in Method 8 will be required to calculate the total sulfur oxides with sulfur dioxide (SO_2) as the surrogate compound. Currently, Method 8 specifies that the isopropanol (including probe wash and filter) analyses results be reported as sulfuric acid. To report the isopropanol (including probe wash and filter) analyses results as SO_2, the regulation should indicate that equation 8-3 be specified in Section 6.5 of Method 8 in lieu of equation 8-2. The total sulfur oxides emission concentration as SO_2 would then be calculated as the sum of the results from Sections 6.5 and 6.6 of Method 8.

Method 8 has provisions (subject to Administrator approval) for determining filterable particulate matter along with sulfur dioxide by inserting a heated filter between the probe and isopropanol impinger. Sufficient information is not currently available to recommend an acceptable analysis procedure to obtain total sulfur oxides from this sampling arrangement. Therefore, it is recommended that the source use separate sampling trains to determine filterable particulate matter and total sulfur oxides. Additional method development work is planned to determine if an acceptable analytical procedure can be specified.

If the recommended standard is in a kilogram SO_x per 1,000 kilogram coke burn-off format, then Reference Methods 1, 2, 3, 4, and 6 would be required at the control device exhaust to determine SO_2 emission rates in kilograms SO_x per unit time. In addition, Methods 1, 2, 3, and 4 would be required after the catalyst regenerator and prior to the control device. In addition, the air flow rate into the FCCU catalyst regenerator would be required.

Calculation procedures for SO_x emissions should be the same as for particulate matter. Since the particulate matter NSPS requires the plant to supply the air flow rate (Q_{RA}) into the FCCU catalyst regenerator, it also should be acceptable for SO_2.

The testing performed by EPA utilized a modified Reference Method 8 procedure to determine the SO_3/SO_2 ratio and to guard against interferences due to possible free ammonia in the stack gas. Section D.1 provides a detailed discussion of the procedures used by EPA.

The cost for conducting a performance test using the procedures above are estimated to range from \$2,500 to \$3,500, plus travel time, travel costs, and subsistence. The test would require three test runs at each affected facility. The test would require about 10 person days. There would be no substantial difference in cost to conduct a performance test in either emission format.

D.3.2 Feed Sulfur Levels

A performance test method which can be used on a continuing basis is required to ensure that the sulfur content of the FCCU feed is maintained less than a certain level. The performance test method needs to specify the FCCU feed sampling location, the sampling frequency, the sample sulfur content analysis method, and the procedure for applying the analysis results to determine compliance with the standard.

The feed processed by an FCCU is a blend of feedstock streams obtained directly from various process units (e.g., atmospheric and vacuum distillation units) or pumped from storage tanks. These feedstock components are termed fresh feed. For many FCCU designs, the fresh feedstocks are combined into a single feed stream for injection into the FCCU riser/reactor. However, for some FCCU designs, the fresh feed components are injected into the riser/reactor at multiple locations. Prior to injection of the combined fresh feed into the FCCU, many refiners add a small amount of recycle oil pumped from the FCCU fractionator. Presently, refiners routinely sample the FCCU fresh feed upstream of the point where recycle oil is added. Because the addition of recycle oil does not affect SO_x emissions from the FCCU regenerator, it is not reasonable to require refiners to modify their FCCU feed sampling locations. Therefore, the performance test method would require the sampling of the FCCU fresh feed. For FCCU's processing a single fresh feed stream, refiners would be required to sample the feed at only one location. Where the fresh feed is injected into the FCCU at multiple locations, sampling the fresh feed at each location would be necessary.

Refiners can vary the FCCU fresh feed components and, thus, change the sulfur content of the fresh feed on a daily or even hourly basis. Currently, most refiners manually sample the FCCU fresh feed once per day. Automated sampling equipment for sampling the hot, pressurized FCCU fresh feed has not been demonstrated. Consequently, the required frequency at which samples are to be collected must be comprehensive to ensure that fluctuations in FCCU feed sulfur levels are measured, yet at the same time, be practical with respect to manual sampling techniques. Although FCCU fresh feed sulfur content may change on an hourly basis, requiring samples be collected once per hour is not practical using manual sampling techniques. An alternative interval is to sample once per 8-hour shift. This interval is frequent enough to measure major fluctuations in the fresh feed sulfur level and is reasonable considering current refinery sampling practices. Therefore, the performance test method would require the sampling of FCCU fresh feed once every 8-hour shift.

Refiners utilize a variety of analytical methods for determining the sulfur content of the FCCU fresh feed. The type of methods used can vary from one refiner to another. For compliance purposes, a performance test method needs to be specified which will give consistent results for all refiners. The American Society for Testing and Materials (ASTM) has specified four analytical test methods for determination of sulfur in petroleum products. These are ASTM D129 (General Bomb Method), ASTM D1266 (Lamp Method), ASTM D1552 (High Temperature Method), and ASTM D2622 (X-Ray Spectrographic Method). Selection of the ASTM method to be used for compliance determination is based on repeatability, reproducibility, and cost. All four of the ASTM methods yield results having similar repeatability and reproducibility. The analytical equipment required to perform these tests is presently used by refiners to perform other types of routine analyses. Consequently, the costs of using the different test methods are comparable. Since all four ASTM methods yield similar results in terms of repeatability and reproducibility, it is reasonable to allow a refiner to utilize any one of the four methods for FCCU fresh feed sulfur determinations.

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APPENDIX E
PROJECTED GROWTH IN FCCU CAPACITY

APPENDIX E. PROJECTED GROWTH IN FCCU CAPACITY

E.1 INTRODUCTION

The number of new, modified, and reconstructed FCC units anticipated over the five-year period from 1982 through 1986 is determined in this section. These projections are used in Chapters 7, 8, and 9 to determine the environmental, energy, and economic impacts of the regulatory alternatives.

E.2 HISTORICAL FCC GROWTH DATA

Total nationwide growth in FCC fresh feed capacity is dependent upon three factors; new unit construction, increases to existing capacities, and decreases to existing capacities due to removal or shutdown. By reviewing available literature and recording the individual changes in refinery FCC throughput capacities from 1971 to 1980 an estimation of total nationwide growth in FCC fresh feed capacity was made.

FCC fresh feed capacities for the years 1971 to 1980 are shown in Table E-1. As the table indicates, nationwide FCC fresh feed capacity has increased from about 616,200 m^3/sd in 1971 to 803,900 m^3/sd in 1980.[1-11] This represents a net growth of approximately 187,800 m^3/sd. This net growth includes not only capacity increases due to new unit construction and throughput increases but also, decreases in capacity caused by plant closures and decreases in individual FCC throughput. To accurately represent gross nationwide FCC fresh feed capacity increases from 1971 to 1980, new unit construction and increases to existing capacity must account for plant closures or decreases in capacity.

The decrease in capacity from 1971 to 1980 was approximately 64,500 m^3/sd[1-11], or an average annual decrease of about 7,200 m^3/sd-yr. Gross nationwide FCC capacity increases are determined by adding the total 1971 to 1980 decreases to the 1971 to 1980 net capacity increase. Thus, in this time period, new unit construction and increases to existing capacity (gross nationwide growth) amounted to 252,300 m^3/sd.

TABLE E-1. U.S. FCCU FRESH FEED CAPACITY 1971-1980 (January 1)[1-11]

YEAR	FRESH FEED CAPACITY m^3/sd
1971	616,164
1972	634,332
1973	641,631
1974	673,052
1975	692,078
1976	706,529
1977	735,589
1978	739,827
1979	759,021
1980	803,929

Table E-2 lists FCC unit regenerator new unit construction from 1971 to 1980. During this period, 18 new FCC units were constructed, or an average of approximately 2 new units per year. The FCC fresh feed capacity increase due to this new unit construction was 97,500 m^3/sd, or approximately 39 percent of the gross nationwide capacity increase. The remaining 61 percent of the gross nationwide capacity increase, approximately 154,800 m^3/sd, were attributable to increases in existing capacity. In the 5-year period from 1975 to 1980, 70 different existing units contributed to these gross nationwide FCC capacity increases.

Figure E-1 presents the size distribution of the new FCC units constructed between 1971 and 1980. As the figure illustrates, the most common new units constructed had capacities near 2,500 m^3/sd, 8,000 m^3/sd, and 12,000 m^3/sd.

E.3 FIVE-YEAR GROWTH PROJECTION

A 5-year growth projection of FCC fresh feed capacity can be obtained if a linear approximation is made using a least-squares fit to the historical FCC fresh feed capacity data. The result of the linear approximation is graphically presented in Figure E-2. The projected annual capacities generated by the linear approximation are presented in Table E-3. As the table indicates, FCC fresh feed capacity is expected to increase from approximately 828,500 m^3/sd in 1982 to 927,100 m^3/sd in 1987. This represents a projected net growth of 98,600 m^3/sd from 1982 to 1987. To account for projected decreases in capacity caused by plant closures or decreases in individual refinery capacity, it is assumed that the projected average annual decrease in FCC throughput is the same as the historical decrease in capacity, 7,200 m^3/sd-yr. The resulting gross FCC fresh feed capacity increase due to new unit construction and increases to existing plants is about 134,500 m^3/sd

Growth due strictly to new unit construction is determined by assuming that about 39 percent of the gross nationwide FCC capacity growth is due to new unit construction. This reflects the historical construction pattern. Between 1982 and 1987, about 52,150 m^3/sd of the gross FCC capacity growth may be provided by new units. If 2 new units are fabricated each year between 1982 and 1987, a total of

TABLE E-2. FCCU REGENERATOR NEW UNIT CONSTRUCTION 1971 - 1980[1-11]

YEAR	UNIT AND LOCATION	FRESH FEED CAPACITY m^3/sd
1971	Gulf Oil Company, Belle Chasse, LA	11,446
1972	Mobil Oil Corporation, Joliet, IL	10,492
	Mobil Oil Corporation, Beaumont, TX	8,743
1973	Conoco, Commerce City, CO	2,226
	Sun Oil Company, Toledo, Ohio	7,949
	Conoco, Ponca City, OK	4,769
	Arizona Fuels Corporation, Roosevelt, UT	954
1974	Good Hope Rfg., Good Hope, LA	2,385
	Texas City Rfg., Texas City, TX	4,292
1975	No New Units	0
1976	Navajo Refining, Artesia, NM	827
	Champlin Petroleum Corporation, Corpus Christi, TX	6,518
1977	No New Units	0
1978	Good Hope Rfg., Good Hope, LA	7,631
	Plateau Incorporated, Bloomfield, NM	795
1979	Conoco, Lake Charles, LA	4,864
	Marathon Oil Company, Garyville, LA	11,923
	Murphy Oil Corporation, Meraux, LA	3,942
	Placid Rfg., Port Allen, LA	2,623
	Diamond Shamrock Corporation, Sunray, TX	5,167

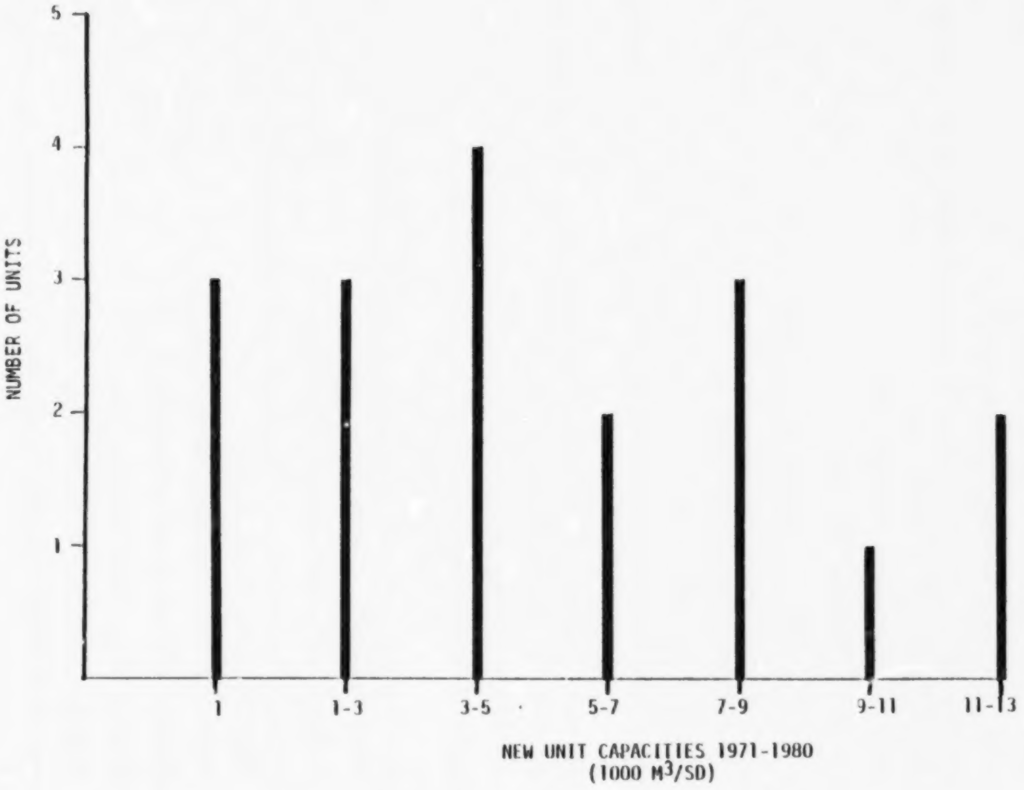

Figure E-1. SIZE DISTRIBUTION OF NEW UNITS CONSTRUCTED BETWEEN 1971 and 1980

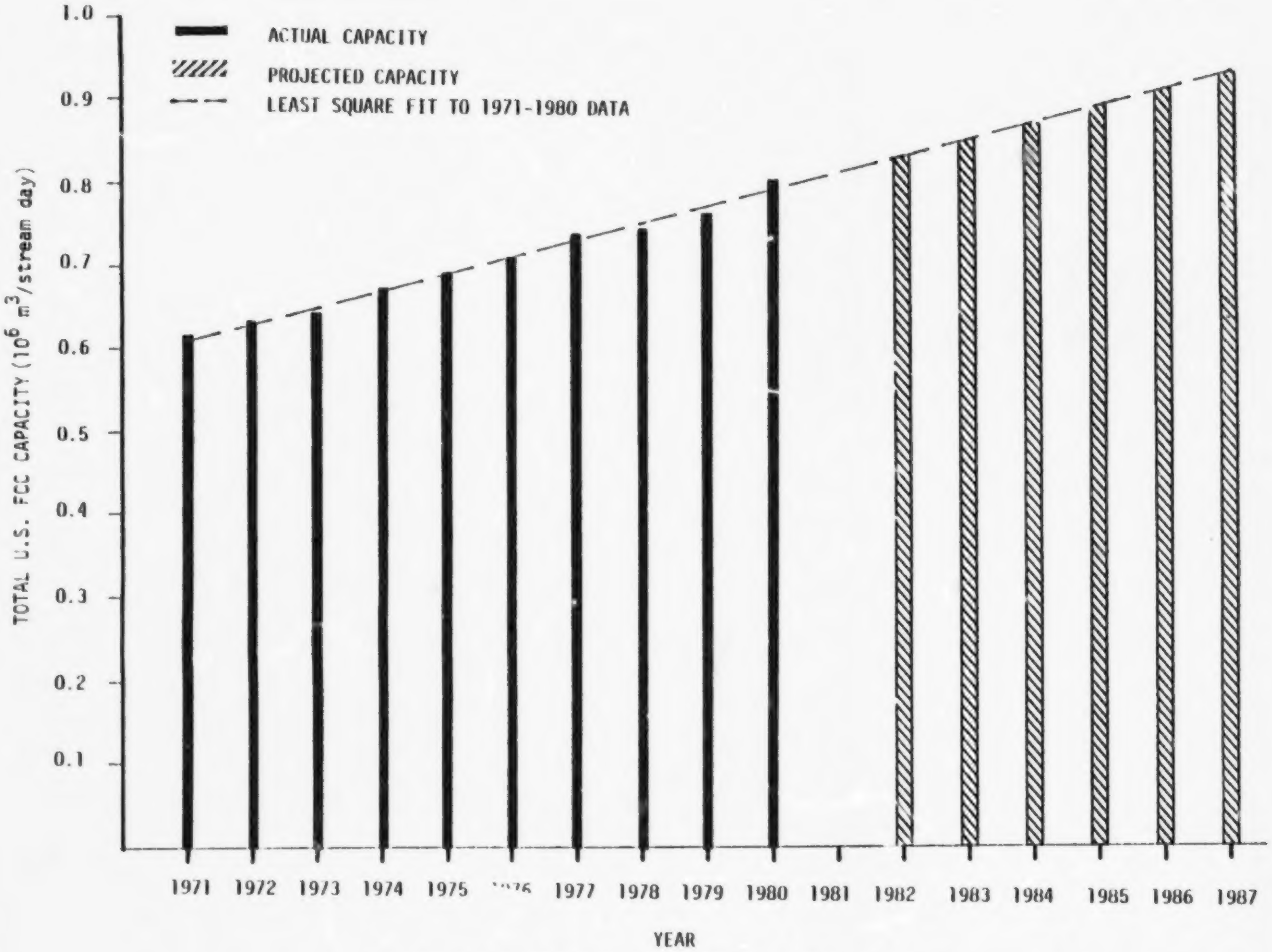

Figure E-2 Projected U.S. FCC Fresh Feed Capacity

TABLE E-3. PROJECTED U.S. FCCU FRESH FEED CAPACITY 1981 - 1987

YEAR	FRESH FEED CAPACITY m^3/sd
1981	808,740
1982	828,470
1983	848,200
1984	867,940
1985	887,670
1986	907,400
1987	927,130

FOR PROJECTION: CAPACITY = 19731.8(YEAR)-38279992

Based on a least squares linear fit to capacity data from 1971 to 1980

10 new units will be in operation by 1987. Based on the size distribution of new units built between 1971 and 1980, these new units will have capacities of about 2,500 m^3/sd and 8,000 m^3/sd. Five of each of these units are expected to be constructed.

The remaining portion of the gross nationwide FCC capacity growth, 82,000 m^3/sd, is attributable to increases in existing capacity. As many as 70 units may contribute to these capacity increases. This number, however, does not reflect increases in capacity without a capital expenditure, which is specifically exempted from the modification provisions.

A survey of refiners who have increased FCC unit capacity in the last five years was conducted to provide an estimate of the number of units which would become subject to the modification and reconstruction provisions. Of the twelve refiners contacted,[12-27] two performed alterations to the FCCU catalyst regenerator or air blower which could have been modifications or reconstructions. The other refiners increased throughput by debottlenecking upstream or downstream from the FCCU catalyst regenerator. On this basis it was concluded that only about 10 percent of the 70 potential units would modify or reconstruct. Thus, only seven units are expected to modify or reconstruct in the five years after proposal of the standard.

The distribution of unit sizes involved in modification and reconstruction was determined by observing that modifications and reconstructions are more likely to occur with large FCC units. On this basis, it was specified that five units with 8,000 m^3/sd capacity and two units with 2,500 m^3/sd capacity would be reconstructed or modified between 1982 and 1987.

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APPENDIX F

Analysis of Heavy Oil Cracker SO_x Emissions and Control Costs

APPENDIX F. ANALYSIS OF HEAVY OIL CRACKER SO_x EMISSIONS AND CONTROL COSTS

F.1 INTRODUCTION

Heavy oil crackers (HOC's) are fluid catalytic cracking (FCC) units that process residual and other heavy oil feedstocks. These HOC feedstocks contain complex sulfur compounds which typically form coke. As a result, a greater portion of the sulfur in HOC feedstocks forms coke than FCC gas oil feeds. In addition, HOC feedstocks have a higher coke make rate than gas oil feeds. Thus, sulfur oxides emissions may be greater from HOC units than from other other FCC units. Therefore, sulfur oxides control costs may differ for HOC and other FCC units. For these reasons, industry representatives commented that HOC's should be considered separately from other FCC units for development of a sulfur oxides emissions standard.

Appendix F analyzes sulfur oxides emissions and emissions control costs for HOC's controlled by sodium-based scrubbers. This analysis was performed to determine if HOC's should be considered separately from FCC units for development of a sulfur oxides emissions limit. In addition, results of this analysis are appropriate for asphalt residual treating (ART) SO_x control costs.[1]

F.2 HOC MODEL PLANT SO_x EMISSIONS

HOC model plants were developed based on information provided by an HOC operator.[2] Operating parameters were provided as a range and are presented in Table F-1. The parameters used to develop HOC model plants were selected from this range.

HOC model plants were constructed in the same way as FCC unit model plants, discussed in Chapter 6. HOC model plant flue gas compositions and flow rates were calculated by selecting the coke composition and formation rate from Table F-1, and by calculating the amount of air required to oxidize the coke.

Model plant sulfur oxides emissions are dependent upon parameter selection. Since most of the HOC operating parameters were provided as a range, it is necessary to determine the sensitivity of model plant sulfur oxides emissions to parameter selection. This was accomplished by varying one parameter at a time, selecting the highest and lowest

Table F-1. ASSUMPTIONS USED TO DEVELOP HOC MODEL PLANTS

Combustion Air Composition

O_2 content = 20 percent

H_2O content = 1.2 percent

N_2 content = 78.8 percent

Flue Gas Composition

Excess O_2 content = 2 percent

CO content = negligible

	Nonhydrotreated Feeds	Hydrotreated Feeds
Feedstock		
Density	900 kg/m^3	900 kg/m^3
Sulfur content[a]	1-4 weight percent	0.3-0.45 weight percent
Coke Composition[a]		
Sulfur content	2.75 x feedstock sulfur content	3 to 3.5 x feedstock sulfur content
Coke make rate	8-15 weight percent	8-12 weight percent
Coke hydrogen content	Not available	5-8 weight percent

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[a] Reference 2.

value for the parameter, then calculating HOC model plant emissions. HOC model plant parameters used and results of the sensitivity analysis are presented in Table F-2. The parameters which were varied are feed sulfur content (Case 1), coke sulfur content (Case 2), coke make rate (Case 3), and coke hydrogen content (Case 4).

Results of the sensitivity analysis show that HOC model plant sulfur oxides emissions are most sensitive to the feed sulfur content. From Table F-2, HOC model plant sulfur oxides emissions range from 530 vppm (17.9 kg/1,000 kg coke burn-off) to 6,500 vppm (209 kg/1,000 kg coke burn-off).

F.3 HOC MODEL PLANT CONTROL COSTS

Sulfur oxides control costs were developed for the HOC model plants by using model plant flue gas characteristics and the costs and assumptions presented in Chapter 8 for sodium-based scrubbers. For this analysis, utility costs are assumed proportional to the HOC model plant air flow rate to the scrubber. No credit was taken in this analysis for scrubber particulate control. Therefore, the results represent a conservative estimate of control costs.

Results of the cost analysis are presented in Table F-3 for each of the HOC model plants developed and represent an analysis of the sensitivity of control costs to HOC model plant parameter selection. Annual costs for the sodium-based scrubber range from about $8 million for Case 2A to $20 million for Case 1B. Cost effectiveness for the HOC model plants ranges from $390/Mg SO_x removed for Case 1B to about $1,600/Mg SO_x removed for Case 1A. For comparison, the cost-effectiveness values reported in Chapter 8 for sodium-based scrubbers applied to FCC units processing gas oils range from $400 to $5,080/Mg SO_x removed. This analysis shows that HOC sulfur oxides control costs, in terms of cost effectiveness, are similar to FCC control costs. As such, this analysis does not support the development of separate regulatory alternatives for HOC's.

Annual sulfur oxides control costs for the high feed sulfur HOC model plant (Case 1B) are $20 million. The corresponding cost effectiveness for this model plant is $390/Mg SO_x removed. This HOC model plant is based on high sulfur residual feeds. These feeds, and

Table F-2. HOC MODEL PLANT SENSITIVITY ANALYSIS, PARAMETERS USED AND RESULTING SO_x EMISSIONS

Case	Model Plant Size, m^3/sd	Feedstock Sulfur Content, Weight Percent	Coke Make Rate, Weight Percent of Fresh Feed	Coke Composition (wt. %)			SO_x Emissions		Comments
				Hydrogen	Sulfur	Carbon	kg/1,000 kg Coke Burn-off	vppm	
Base	8,000	1.5	10	6.5	4.5	89	89.7	2,700	
1A	8,000	0.3	10	6.5	0.9	92.6	17.9	530	Change in feed sulfur content.
1B	8,000	3.5	10	6.5	10.5	83	209	6,500	
2A	8,000	1.5	10	6.5	4.1	89.4	82.3	2,500	Change in coke sulfur content.
2B	8,000	1.5	10	6.5	5.3	88.2	105	3,200	
3A	8,000	1.5	8	6.5	4.5	89	89.7	2,700	Change in coke make rate.
3B	8,000	1.5	12	6.5	4.5	89	89.7	2,700	
4A	8,000	1.5	10	5	4.5	90.5	89.7	2,800	Change in coke hydrogen content.
4B	8,000	1.5	10	8	4.5	87.5	89.7	2,600	

Table F-3. HOC MODEL PLANT CONTROL COSTS AND COST EFFECTIVENESS[a]

Case	Air Flow Rate into Scrubber Sm^3/min	SO_x Emission Reduction Mg/yr	Annual Cost $1,000's	Cost Effectiveness $/Mg SO_x Removed	Percent Change from Base
BASE	6,340	20,500	9,500	460	--
1A	6,500	2,000	3,100	1,570	240
1B	6,130	51,300	20,200	390	-15
2A	6,350	18,500	8,800	480	4
2B	6,310	24,300	10,800	450	-2
3A	5,070	16,400	7,800	480	4
3B	7,610	24,600	11,200	450	-2
4A	6,130	20,600	9,500	460	0
4B	6,550	20,400	9,500	470	2

[a] Costs provided are based on controlling emissions to Regulatory Alternative III, 300 vppm.

crudes from which they are derived, are typically sold to refiners at a reduced cost. Therefore, the high annual control costs for this model plant would be offset by the lower crude costs. Secondly, it is doubtful that HOC's would process these heavy feedstocks without hydrotreating. Hydrotreating would reduce the sulfur content of the feedstock and, therefore, reduce the annual cost of sulfur oxides emissions control.

F.4 REFERENCES

1. Memorandum from Bernstein, George, Pacific Environmental Services, Inc., to Docket A-79-09. September 20, 1982. Similarity in Control Costs between Heavy Oil Crackers and the Asphalt Residual Treating Process. Docket Reference Number II-B-29.*

2. Telecon. Barrett, J., Phillips Petroleum Company, with Bernstein, G., Pacific Environmental Services, Incorporated. February 22, 1982. Docket Reference Number II-E-7.*

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*References can be located in Docket Number A-79-09 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.